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A Case Study Review of Technical and Technology Issues for Transition of a Utility Load Management Program to Provide System Reliability Resources in Restructured Electricity Markets

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[1] This report does not necessarily represent the opinions of the Southern California Edison company.

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Acronyms

AC	alternating current
AEM	advanced energy management
AGC	automatic generation control
AMR	automated meter reading
ANSI	American National Standards Institute
ATM	asynchronous transfer mode
C	Centigrade
C & I	commercial and industrial
CAP	competitive access provider
CCU	carrier control unit
CD	compact disk
CDPD	cellular digital packet data
CIMS	customer information management system
CIS	customer information system
CRC	cyclical redundant checking
CVU	coverage validation unit
dB	decibel
DSM	demand-side management
DSSI	Data Systems and Software, Inc.
EMS	energy management system
FCC	Federal Communications Commission
FEC	forward error correction
FERC	Federal Energy Regulatory Commission
FSK	frequency shift keying
GB	gigabyte
HFC	hybrid fiber optic/coaxial
Hz	hertz
ICU	interactive control unit
IEEE	Institute of Electrical and Electronic Engineers
IGSP	internet gateway service provider
IP	Internet Protocol
ISO	independent system operator
ISP	internet service provider
IT	information technology
iTC	Internet Telemetry Corporation
IXC	InterExchange Carrier
kHz	kilohertz
LAN	local area network
LATA	local access and transport area
LCR	load control receiver
LCD	liquid crystal display
LED	Light emitting diode
MAS	multiple address system
Mb	megabyte

MCC	microcell controller
MIU	meter interface unit
MW	megawatts
NEMA	National Electrical Manufacturers' Association
PC	personal computer
PSTN	public, switched telephone network
QAM	quadrature amplitude modulation
QPSK	quadrature phase shift keying
R&D	research and development
RAM	random access memory
RF	radio frequency
ROI	return on investment
RTC	remote transmitter controller
RTP	real-time pricing
SA	Scientific Atlanta
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SCU	signal coupling unit
SQL	structured query language
SSH	secure shell
SVGA	super video graphics array
TOU	time of use
TWACS	two-way automatic communication system
UHF	ultra high frequency
UL	Underwriters Laboratory
VHF	very high frequency
WAN	wide-area network

Abstract

Utility load management programs – including direct load control and interruptible load programs – were employed by utilities in the past as system reliability resources. With electricity industry restructuring, the context for these programs has changed; the market that was once controlled by vertically integrated utilities has become competitive, raising the question: can existing load management programs be modified so that they can effectively participate in competitive energy markets? In the short run, modified and/or improved operation of load management programs may be the most effective form of demand-side response available to the electricity system today. However, in light of recent technological advances in metering, communication, and load control, utility load management programs must be carefully reviewed in order to determine appropriate investments to support this transition.

This report investigates the feasibility of and options for modifying an existing utility load management system so that it might provide reliability services (i.e. ancillary services) in the competitive markets that have resulted from electricity industry restructuring. The report is a case study of Southern California Edison's (SCE) load management programs. SCE was chosen because it operates one of the largest load management programs in the country and it operates them within a competitive wholesale electricity market. The report describes a wide range of existing and soon-to-be-available communication, control, and metering technologies that could be used to facilitate the evolution of SCE's load management programs and systems to provision of reliability services. The fundamental finding of this report is that, with modifications, SCE's load management infrastructure could be transitioned to provide critical ancillary services in competitive electricity markets, employing currently or soon-to-be available load control technologies.

1. Introduction

Utility load management programs, including direct load control and interruptible load programs, constitute a large installed base of controllable loads that were employed by utilities in the past as system reliability resources. With electricity industry restructuring, the context for these programs has changed; the market that was once controlled by vertically integrated utilities has become competitive, raising the question: can existing load management programs be modified so that they can effectively participate in competitive energy markets. The underlying communication, control, and metering technologies as well as the designs and operational procedures of these programs have not been appraised for the value they could offer in competitive markets. In the short run, modified operation of load management programs may be the most effective form of demand-side response available to the electricity system today. However, in light of recent technological advances in metering, communication, and load control, existing utility load management must be carefully reviewed in order to determine appropriate investments to support this transition.

Existing interruptible load programs are especially promising potential participants in competitive markets because these programs already have many characteristics that could be incorporated into the future reliability-motivated load participation programs: (1) interruptions are triggered by a signal form the utility in response to system conditions; (2) customers have substantial discretion about the manner in which load is shed, in some cases including reliance on distributed generation (in contrast to direct load control programs that turn off designated pieces of end-use equipment); (3) customers at times have discretion about whether to interrupt at all; and (4) the utility already has procedures in place to verify interruptions .

This report presents a detailed case study of the load management assets at Southern California Edison (SCE). SCE has one of the largest installed bases of load management capability (>2,300 MW) in the U.S and also operates in one of the most closely watched restructuring electricity markets in the nation. This study assesses the technical issues that must be addressed and the options available for addressing these issues if SCE's load management system is to transition from providing reliability services in the vertically integrated utility industry to operating as a reliability resource in competitive electricity markets.[2]

This report is organized in three sections following this introduction.

Section 2 describes the aspects of SCE's current load management programs and systems that are examined in this report.

Section 3 assesses the technical requirements for system reliability services that might be provided by these load management assets in the future. The assessment compares the requirements for provision of various ancillary services with the communication, control, and metering requirements these services would impose on a SCE's load management infrastructure.

[2] This report does not necessarily represent the opinions of the Southern California Edison company.

Section 4 reviews a variety of commercially available communication, control, and metering technologies that could help facilitate a transition from SCE's current load management system to an enhanced system capable of providing a variety of system reliability services in the future.

Appendix A provides detailed technical specifications for SCE's load management infrastructure that would be needed to support that transition of SCE's direct load control programs to provision of system reliability resources in California's competitive wholesale electricity market.

Appendix B provides product information on a technology that could be used to provide voltage control through a load management program infrastructure.

2. SCE's Load Management Programs and Systems SCE'S LOAD

This section provides a detailed example of a large utility's current load management programs and system components (e.g., computer, communications, metering). This example is taken from Southern California Edison's (SCE's) direct load control (DLC) program.

Figure 2-1 illustrates the major functional elements of SCE's DLC programs, including the load control receiver (LCR), data communications, the master computer, and the metering system.

<u>Load Control Receiver (LCR)</u> - The critical requirement of the LCR is its ability to respond to a control command within a time frame that would allow its impact (i.e., demand reduction) to be realized at the system level soon enough to provide the necessary load shift. Since the time frame "order of magnitude" is specified in minutes (rather that seconds or fractions of seconds), the only requirement of the LCR is to be able to respond with adequate speed. The LCRs are microprocessor controlled and have no internal time delay. Hence, the LCRs themselves can easily provide this kind of fast load relief load to the electric grid. The ability to get the message to the receiver on time is an additional requirement that will be discussed next.

<u>Data Communications</u> - For traditional Direct Load Control (DLC) systems, the data communications capability of the load control system is the key limiting factor in its ability to supply reliability or ancillary services. This fact is based on the typical performance of a dedicated communication infrastructure - one that is owned and operated by the utility and one that provides dedicated access.

However, it is important to consider that in many instances around the country, the communications system (or more accurately the frequency) must be shared with other utilities. This "sharing" of the communications system inherently makes the communications system unavailable for critical "time specific" transmission of the control messages. Other systems around the country also share the communications medium with paging system providers raising the same issues. Even in an ideal situation where an owned and dedicated system exists, the communications network combined with the receiver response makes these types of direct load-control systems unacceptable for extremely fast load response applications (e.g., regulation).

The typical response time for a DLC system in a dedicated environment is approximately 10 seconds. This means that from the time the system is "commanded" to shed load to the time the load is actually shed is about 10 seconds. The SCADA system must then detect the load shed and feed that information back to the AGC system. It is assumed here that the AGC system requires a more instantaneous response in order to maintain ACE.

Another consideration is that the DLC system must control loads (especially diversified loads such as Air Conditioners) in such a way that their loads do not loose their natural diversity [critical where duty cycle control (i.e. 15 minutes off and 15 minutes on) is being implemented]. This issue implies that the loads are not merely turned off but must be continuously cycled on an appropriate time base (e.g., 30 minutes).

Another complexity occurs as the DLC system transitions from apparent load reduction, the effect of the first load shed command which is basically the average diversified demand of the appliance being controlled, to a more sustainable continuous average load reduction value, integrated over an hour. The sustainable load reduction is considerably less than the apparent load reduction observed early in the load shed process. In summary, as the controlled appliances are cycled and become "in synch" with control process, the only sustainable load reduction is a result in the lowering of the natural duty cycle of the appliance. This actual load reduction is significantly less than the average diversified demand of the appliance.

Master Computer - The Master Computer technical requirements are relatively simple from a control perspective. The computer should support a concept known as "Distributed Intelligence" where the LCR determines on its own when to start and stop control thus maintaining appliance diversity. As long as the end control device (i.e., LCR) has this capability, the complexity of the control schemes that must be written into the Master Control Computer can be kept relatively simple. There are no inherent limitations to the Master Control Computer that inhibit the system's ability to provide ancillary services.

Metering Systems - For a traditional Direct Load Control system, the metering requirements at the individual customer level do not change. However, if the utility needs to understand what is actually happening at each individual customer (not the case for conventional systems) then the meter would have to be automated so that interval (e.g., 5, 10, 15 minute) consumption data could be retrieved and analyzed to determine the actual performance of each load control command and event.

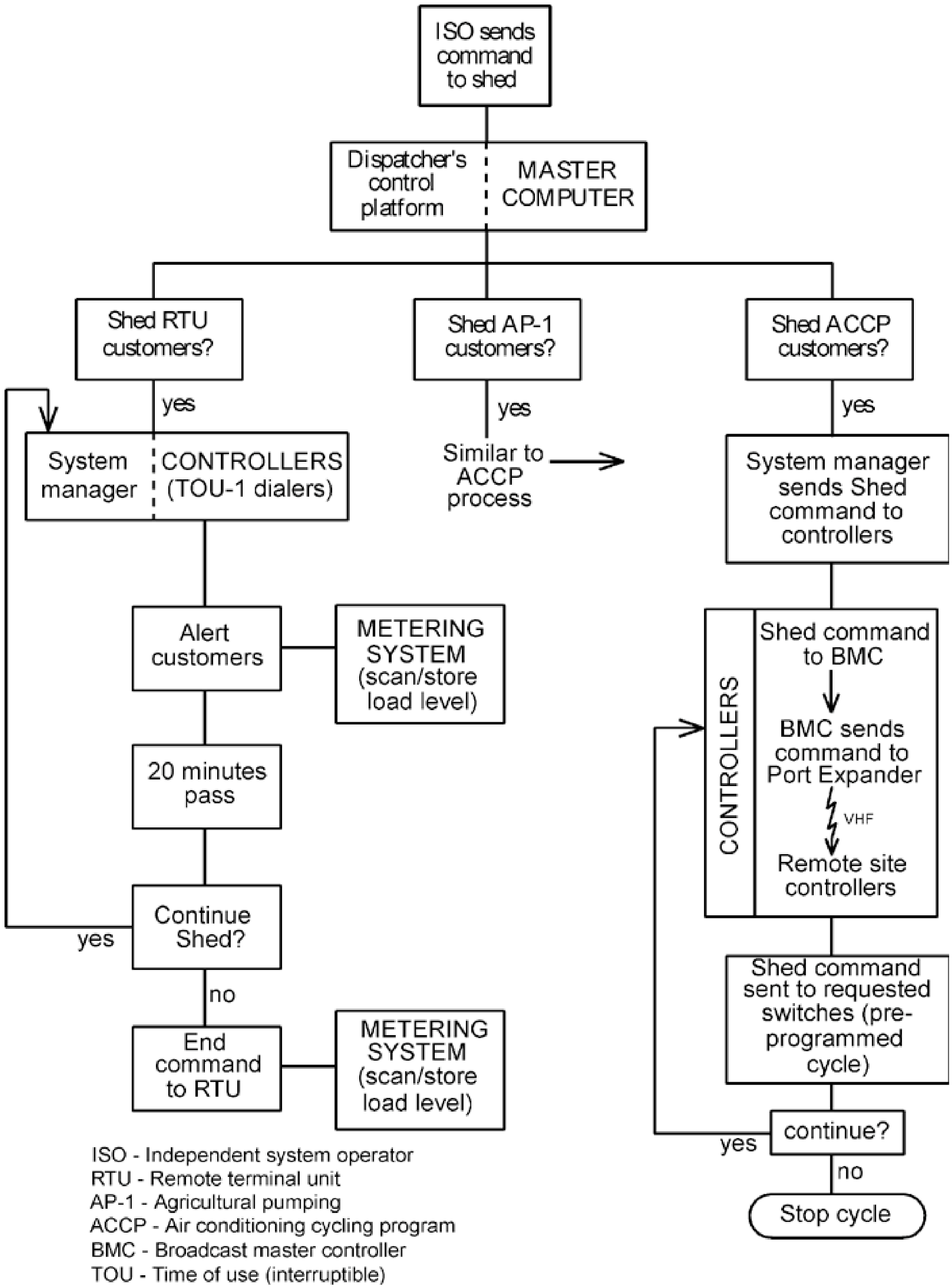

Figure 2.1 Typical Load Management System Interface/Data Flow

3. Requirements for Load Management Resources to Provide Ancillary Services Resources to Provide Ancillary Services

This section reviews the requirements for demand-side participation in reliability markets, including conventional and near-term future control and communication needs and hardware specifications for each ancillary service. The following ancillary service markets are addressed in the subsections below:

- Regulation
- Load Following
- Voltage Control
- Spinning Reserve
- Supplemental Reserve
- Back-up Supply
- Dynamic Scheduling
- System Black Start
- Time of Use (TOU)

3.1 Ancillary Services Markets

Each subsection below describes technical requirements for the LCR, data communications, master computer, and metering systems for each ancillary service discussed. Detailed technical specifications supporting these descriptions are provided in Appendix A.

3.1.1 Regulation

Regulation is the use of on-line generation units equipped with automatic generation control (AGC). These units can change output quickly (MW/minute) to track moment-to-moment fluctuations in customer loads and unintended fluctuations in generation. Regulation helps to maintain interconnection frequency, minimize differences between actual and scheduled power flows between control areas, and match generation to load within a control area. This service can be provided by any appropriately equipped generator that is connected to the grid and is close enough to the local control area, so that physical and economic transmission limitations do not prevent the import of its power.

3.1.1.1 Load Control Receiver - Overall Technical Requirements

The critical LCR requirement for the regulation ancillary service is the ability to respond to a control command swiftly enough so that demand reduction is realized at the system level to shift load as rapidly as necessary. LCRs are all microprocessor-controlled, so their response time should be sufficient to meet the time frame for this ancillary service, which is typically specified in minutes (rather than seconds or fractions of seconds). Getting the desired control message to the receiver in time to implement the desired load reduction is another matter, however. This requirement will be discussed in the next subsections.

For traditional direct load control systems, the data communications capability is the key factor that limits the system's ability to supply reliable regulation ancillary services. This analysis is based on the typical performance of a dedicated communications infrastructure – one that is owned and operated by the utility and that provides dedicated access. In many instances around the country, communications frequencies must be shared with other utilities, which means that the communications system may be unavailable for critical, time-specific transmission of control messages. Some systems around the country share their communications medium with paging system providers, which creates a similar problem. Even in an ideal situation – an owned and dedicated system – network latency combined with receiver response makes these types of direct load control systems unacceptable for regulation applications. When a direct load control system is in a dedicated environment, a command to shed load typically takes on the order of 10 seconds to execute. The system SCADA must then detect the load shedding and feed that information back to the AGC system. It is assumed that the AGC system requires a more instantaneous type of response in order to maintain Area Control Error (ACE).

Another consideration is that the direct load control system must manage loads (especially diversified loads such as air conditioners) so that natural diversity is not lost (this is critical where duty-cycle control, e.g., 15 off / 15 control, is being implemented). Load must not be merely turned off but must be continuously controlled (on and off) according to a time base, e.g., 30 minutes. This time frame implies that stopping and starting control is a drawn-out process. Another complexity occurs as the direct load control system transitions from apparent load reduction – the effect of the first load-shedding command (which is basically the average diversified demand of the appliance being controlled – to a more sustainable continuous average load reduction value, integrated over an hour. This sustained value is considerably smaller than the apparent load reduction that is observed early in the load shed process. In other words, as controlled appliances synchronize with the control process, the only sustainable load reduction results from the lowering of the overall natural duty cycle of the appliances. This actual load reduction is significantly less than the average diversified demand of the appliance unless the controlled duty cycle is 100 percent.

3.1.1.2 Master Computer Overall Technical Requirements

The master computer technical requirements for the regulation ancillary service are relatively simple. As long as the end control device (LCR) is relatively "smart," i.e., it supports distributed intelligence (where the LCR determines, on its own, when to start and stop control, automatically maintaining appliance diversity), the control schemes that must be written into the master control computer can be kept relatively simple. There are no inherent limitations in the master control computer that would affect the system's ability to provide this ancillary service.

3.1.1.3 Metering Systems Overall Technical Requirements

If a traditional direct load control system is used to provide regulation ancillary services, there are no special metering requirements at the individual customer level. If, however, the utility needs to understand what is actually happening at each individual customer site (which is not possible with conventional systems), meters would have to be "automated" so that interval (five-,10-,15-minute, etc.) consumption data could be retrieved and analyzed to determine actual performance during each load control event.

The types of load control being discussed in this report are focused primarily on the mass market. Therefore, the most practical method of determining system performance is statistical, which means that individual customer performance is inferred from load research performed on a valid statistical sample of the general population. Overall system performance, in aggregate, can be recorded at the system level using conventional SCADA monitoring / metering techniques.

3.1.2 Load Following

Load following refers to the use of on-line generation equipment to track changes in customer loads. Load following differs from regulation in three important respects. First, it takes place over longer time intervals (10 minutes or more rather than minute to minute); so different generators are likely to provide this service. Second, the load-following patterns of individual customers are highly correlated with one another, in contrast to regulation patterns, which are largely uncorrelated. Third, load-following changes are often predictable (e.g., because of the weather dependence of many loads) and have similar day-to-day patterns. Customers can also inform the control center of impending changes in their electricity use, and these changes can be captured with short-term forecasting techniques.

3.1.2.1 Load Control Receiver Overall Technical Requirements

LCRs are controlled by microprocessors and can therefore respond to load control commands rapidly enough to provide load following within the time intervals that are necessary.

3.1.2.2 Data Communications Overall Technical Requirements

Because load following requires a basic response time on the order of 10 minutes and because the load-following patterns of many customers are predictable, this service that could be provided effectively by a direct load control system. Direct load control systems' duty-cycled control is an advantage in this scenario because load reduction or increase can be "dispatched" in relatively small increments by simply adjusting the current duty cycle of the appliances being controlled. Adjustments may be on the order of one minute per half hour, for example. The response time of these changes may still be based on a 30-minute time period, but load response can begin almost immediately. Specific control strategies can also be written (although a change in response rate adds complexity to load control strategies and can expose the electricity system to an undamped load swing scenario if not carefully crafted). In summary, there are no inherent limitations in the data communications infrastructure that would prevent a direct load control system from providing load following services.

3.1.2.3 Master Computer Overall Technical Requirements

The master control computer must be able to handle the complex control strategies needed to provide the real-time / on-time responses required by the system dispatcher for load following. The master computer technical requirements should not be an issue if the basic software can respond to these functional requirements. Because load following is predictable and takes place over relatively long time frames (10 minutes), the master computer should be able to handle all other requirements.

3.1.2.4 Metering Systems Overall Technical Requirements

Load following does not affect metering system requirements unless individual customer responses must be verified, which would require meter automation that supports data collection at intervals on the order of one, five, 10 and 15 minutes. These intervals provide sufficient information for monitoring individual system performance. This approach is in some ways preferable using to a direct load control system that monitors itself (a so-called two-way system) because all forms of system failure, e.g., tampering, improper appliance function, poor communications, hardware failure, etc. – can be captured. Without metered data, the LCR can only report its own status and not the status of the entire installation.

3.1.3 Voltage Control

Voltage control entails the injection and / or absorption of reactive power, normally from generators, to regulate transmission voltages. Even though loads themselves cannot logically supply these requirements, the load control system could be used to operate reactive power injection / absorption equipment.

3.1.3.1 LCR Overall Technical Requirements

The use of conventional LCRs to control reactive power injection / absorption equipment is quite common in the U.S. Some utilities have opted for sophisticated monitoring and control (a version of traditional SCADA) for these applications primarily because they can justify the additional cost of ensuring that each device goes on line on a real-time basis. The direct load control systems described here are "one way," so the deployment of the reactive power capacity must be monitored using an existing SCADA system. This monitoring can normally take place at the substation if the VAR load on the substation or feeder in question is monitored. The LCR specified in Section 2.1.1 can perform all of the necessary control functions associated with adding or removing reactive power equipment. The only limiting factor is its inherent inability to confirm that the intended control function has been carried out.

3.1.3.2 Data Communications Overall Technical Requirements

Most system dispatchers can wait for a dedicated direct load control system's approximately 10-second response time. A voltage control command would be considered a failure only if a response took minutes.

3.1.3.3 Master Computer Overall Technical Requirements

Most direct load control system controllers available today can support the load control strategies that will have to be written to provide voltage control.

3.1.3.4 Metering Systems Overall Technical Requirements

The only metering requirements for voltage control are associated with the SCADA system. Individual / end-use meters with voltage and general power quality monitoring capability would greatly enhance the voltage control system's sophistication and allow dispatchers to increase the accuracy of their system / distribution voltage adjustments. End-use metering for voltage / power quality has not generally been considered a requirement for utility voltage regulation activities. SCADA monitoring at substations has generally been considered adequate. See Appendix A for a description of a new product that would could be added to a direct load control system used for voltage control.

3.1.4 Spinning Reserve

Spinning reserve is generation that responds immediately (within 10 second) to contingencies and frequency deviations. FERC has defines spinning reserve as the service provided by generating units that are on line and loaded at less than maximum output. These units are available to serve load immediately in an unexpected contingency, such as an unplanned outage of a generating unit. Spinning reserve must respond immediately to the contingency but only has to be available for short periods (e.g. 10 minutes) until supplemental reserve comes on line.

3.1.4.1 LCR Overall Technical Requirements

LCRs are controlled by microprocessors, so they should have no difficulty responding within the short time frames required for spinning reserve services. The only limitation is in the system's ability to sense the need for spinning reserve and then dispatch a command to shed load, which dictates the performance of direct load control systems in providing this ancillary service.

One way to utilize an LCR for spinning reserve would be to incorporate a system frequency monitoring capability. (This option is not included in the basic specifications described in Appendix A). The receiver could then be commanded / armed remotely by the system dispatcher to shed load at a particular frequency e.g., 59.7 Hz. If the system decision-making capability is "preloaded" in the LCR, it is not necessary to communicate with the LCR in real time as is required for dispatchable spinning reserve functionality. The system dispatcher on a manual basis, which would eliminate the risk of the system becoming unbalanced, would most likely determine Restoration of load.

3.1.4.2 Data Communications Overall Technical Requirements

For spinning reserve, the data communications system would have to support real-time control, a capability that cannot be supported by the conventional direct load control systems specified in Appendix A. To eliminate the real-time control requirement for the data communications system, some additional intelligence must be incorporated in the LCR.

3.1.4.3 Master Computer Overall Technical Requirements

To perform spinning reserve functions, the master computer must be able to respond to an under-frequency condition (sensed by an under-frequency relay), select the required load-shedding strategy, and implement the communications and dispatching function, all within 10 seconds. Most direct load control systems in place today could barely support the maximum 10-second requirement. In general, the typical spinning reserve function allocated to direct load control systems would be for the first load-shedding event (e.g., at 59.7 Hz). The direct load control system would be shed first with the hope that this load reduction would stabilize the grid before more loads would need to be shed by the under-frequency control system that is part of any system protection architecture. It is therefore critical that the direct load control system respond in much less that the 10 seconds mentioned above, in order to prevent more critical loads from being shed. In general, the application of conventional direct load control systems for the provision of spinning reserve is not considered practical.

3.1.4.4 Metering Systems Overall Technical Requirements

Metering for spinning reserve would be used primarily for monitoring the performance of the direct load control system, either at the system level or at the end-user location. Metered end-use data would allow for accurate compensation of participants where applicable.

3.1.5 Supplemental Reserve

Supplemental reserve is generating capacity that can respond to contingency situations within a short period of time – usually 10 minutes. Supplemental operation reserve is normally provided by:

- generating units that are on line but unloaded
- quick-start generation
- customer-interrupted load, i.e., load that is curtailed based on a negotiated agreement with a customer.

Supplemental reserve must be maintained for 20 minutes after it responds to a contingency.

3.1.5.1 LCR Overall Technical Requirements

In comparison to the other ancillary services already discussed, supplemental reserve is the easiest service for a direct load control system to provide. LCRs are inherently capable of providing the necessary control activity within the specified time frame (10 minutes).

3.1.5.2 Data Communications Overall Technical Requirements

The technical requirement for data communications for supplemental reserve is the least stringent of the requirements for all the ancillary services discussed up to this point. The data communications capability of all current direct load control systems, dedicated or shared, can easily provide the necessary load reduction within the specified 10-minute time frame.

3.1.5.3 Master Computer Overall Technical Requirements

For supplemental reserve, the master computer simply needs to contain the specific control strategies that are appropriate. This should not be a problem for most direct load control systems.

3.1.5.4 Metering Systems Overall Technical Requirements

As with all of the ancillary services discussed in this report, the ability to monitor each customer's response to a control request would be helpful in determining fair compensation for each individual's actual contribution to meeting system load requirements. Aggregate metering, which is readily available from existing SCADA systems, is more than adequate because overall performance of the direct load control system can be predicted based on past load research experiments and validated after a control event takes place.

3.1.6 Back-up Supply

Back-up supply involves a pre-arrangement that determines how the System Operator will proceed for each load's loss of primary supply. This supply plan takes effect after spinning and supplemental reserves have been exhausted (i.e., after 30 minutes). Some loads may find it attractive to provide back-up supply for other loads. The 30-minute lead time allows these loads to communicate to and curtail their customers to free up power for use as back-up supply.

3.1.6.1 LCR Overall Technical Requirements

Back-up supply can readily be delivered by a conventional direct load control system. The expected duration of time during which back-up supply would be needed could be determined during contract negotiations to assure that the direct load control system is used only in a way that is compatible with customer tolerances (e.g., more than five hours' control of water heaters would likely be unacceptable to many customers). The LCR requirements for providing back-up supply are no more demanding than for any of the other ancillary services described in this report.

3.1.6.2 Data Communications Overall Technical Requirements

The performance capabilities of a conventional direct load control system can accommodate the requirements for providing back-up supply.

3.1.6.3 Master Computer Overall Technical Requirements

The master computer component of a conventional direct load control system can adequately provide this ancillary service.

3.1.6.4 Metering Systems Overall Technical Requirements

The metering requirements for back-up supply are fundamentally different than for most other ancillary services. Each back-up supply provider is a customer, and it is necessary to document that each one meets its contract requirements to shed load. As noted above, a direct load control system can, as part of its design, perform customized load control. However, the conventional metering that utilities have in place probably cannot support the delivery of this ancillary service. Individual metering solutions are required that will most likely need to be read in near-real time. If we assume that it would be sufficient for meters to collect data at 15-minute intervals and to be read once per day, several available metering technologies could be used. Because a back-up supply system will most likely be offered to relatively large commercial and industrial customers who are randomly distributed throughout the service area, a system such as SmartSynch (described in APPENDIX B) would work well. The same meter data could be gathered via conventional telephone-based meter reading systems available from most of the major meter manufacturers as well as dedicated automated meter reading (AMR) system vendors. The main meter manufacturers are ABB, Schlumberger, GE, Siemens, TransData, and Nertec Design. Manufacturers that provide independent, telephone-based meter reading solutions include Teldata, American Innovations, and Meter Technology Corporation.

3.1.7 Dynamic Scheduling

The Federal Energy Regulatory Commission (FERC) defines dynamic scheduling as electronic movement of a generation resource or load from the control area in which it is physically located to a new control area. Real-time metering, telemetering, and computer software and hardware are needed to accomplish this load transfer. A load control program in one utility service territory would need to be paired with a comparable load control program in another utility service territory in order to provide this service. This possibility is not considered in this report because it requires assumptions we cannot make regarding the "partnering" utilities' load management programs.

3.1.8 System Black Start

"Black Start" refers to electric service that can be provided on short notice without supplemental electric power. Black-start units provide start-up service only in the event of a system-wide shutdown (blackout). Only generation units can provide these start-up services. Hence, a direct load control system is not applicable to the provision of this service.

3.2 Current Time-of-Use (TOU) and Real-Time Pricing (RTP) Markets

The subsections below describe TOU and RTP and the overall technical requirements for a direct load control system to provide these services.

3.2.1 Time of Use (TOU)

Time-of-Use (TOU) tariffs are pricing plans that apply to specific times of day. These tariffs are normally fixed – i.e., formally filed with the Public Service Commission and therefore not subject to dynamic fluctuations based on the actual cost of delivering electricity. TOU tariffs are determined by analyzing long-term trends in production costs. Because of the predictability of TOU rates, a dispatchable load control program can easily be set up to automatically minimize customers' use of energy during periods when TOU rates are high.

3.2.1.1 LCR Overall Technical Requirements

Dispatching a direct load control system for a TOU application is exactly as for most conventional direct control except that TOU control is performed in response to the requests of customers who wish to avoid high peak-time rates. In other words, direct load control can enable general customer participation in TOU markets. Mass-market energy customers, especially residential consumers, do not currently have a convenient option for managing their energy consumption. In effect, the utility could implement a load curtailment for a pre-selected end use(s) on behalf of the customer in response to a high TOU price.

Because TOU tariffs are predictable, the LCR could be designed to accept a specific downloadable control strategy for each customer. The LCR would have to be equipped with a real-time clock (which must be synchronized with the system master station) to ensure proper local dispatch of previously downloaded control messages – possibly at midnight the night before they apply. The main benefit of this level of local intelligence is a reduction in data communications requirements. In general, the LCR specified in Section 2.1.1 can perform and deliver this ancillary service.

3.2.1.2 Data Communications Overall Technical Requirements

The functional data communications requirements for TOU tariffs are very similar to those for the other ancillary services discussed above. However, depending on the specificity of the control functions that the utility offers to consumers, the data throughput requirements could overwhelm the communications system. Most direct load control systems today would have to offer, "pre- packaged" control scenarios that would fit most customers' TOU needs. Each customer would then pick the control scenario that best suited its individual requirements.

If a dedicated wide area network (WAN) (i.e., the internet) could provide high-speed data connections to end-use customers, customer-specific control strategies could be offered. This capability is part of conventional direct load control systems.

3.2.1.3 Master Computer Overall Technical Requirements

Master computer technical requirements could be significantly affected by the increased burden of supporting additional control strategies for TOU services. The basic function would remain exactly like that for a traditional direct load control system. In general, as long as the components of the direct load control system (the data communications system, LCRs, and the associated master computer) function as a package, TOU rates will impose no serious constraint on a conventional master computer system.

3.2.1.4 Metering Systems Overall Technical Requirements

A special TOU meter may be able to provide the interval data needed to verify direct load control system performance. Customer benefits of responding to TOU price signals should be reflected in energy bills.

An AMR system is often considered an attractive option for TOU rates because the cost of a sophisticated TOU meter is about the same as that of AMR with a standard revenue meter. With AMR systems, energy consumption is accumulated and reported back to a master station via the most appropriate communications system. The details of implementing an AMR system are beyond the scope of this study, but numerous effective solutions are readily available. These systems use multiple communication infrastructures and display numerous adaptive features for energy monitoring, each of which adds value to the initial investment.

With AMR, most of the analysis of customer demand and / or energy consumption is performed at the master station rather than within the TOU meter. The benefit of using AMR rather than a dedicated TOU meter would be the availability of metered data on demand, which would allow custom billing and other similar services. Customers could also have access to their individual data to date on at least a daily basis by means of the internet.

The minimum technical requirement for AMR would be inclusion of device within or attached to the revenue meter to convert the electromechanical meter's mechanical energy consumption accumulation process into a type of electrical pulse output that could be correlated to energy consumption. Energy consumption could be calculated from the pulses, and the pulse count could be relayed through the AMR system for evaluation, validation, and editing if necessary. As described in Section 4, several attractive AMR systems are currently available.

3.2.2 Real-Time Pricing (RTP)

Real-Time Pricing (RTP) correlates the time of day, week, or month when energy is used to actual production costs at those times. The definition of "time" in RTP varies according to the actual tariff in place – i.e., prices may be posted a day ahead, an hour ahead, etc. As long as the time frame of the notice is within the operating characteristics of the load control system, the system could be used to respond to these price signals.

3.2.2.1 LCR Overall Technical Requirements

Dispatching a direct load control system for an RTP application is exactly the same as for most conventional applications and for the TOU ancillary service discussed above. RTP is similar to TOU rates (and different from the other ancillary services discussed in this report) because the service is performed in response to customer requests to participate in the rate plan. In view of the time frames most often associated with RTP, e.g., an hour ahead, the LCR must be capable of receiving a load-shedding command and implementing it during the hour of interest. An example might be that a customer has selects a strategy that allows the heating of domestic hot water when the price is below \$0.08/kwh. In this case the LCR would use a permissive scheme rather than the interruption scheme that it would normally use.

3.2.2.2 Data Communications Overall Technical Requirements

As for TOU rates, data communications requirements for RTP are quite similar to those for conventional direct load control.

3.2.2.3 Master Computer Overall Technical Requirements

The master communications technical requirements for RTP are quite similar to those for conventional direct load control.

3.2.2.4 Metering Systems Overall Technical Requirements

Of all of the components of load control, the metering system is the element most impacted by RTP. The CellNet system for TOU rates may also be satisfactory for RTP rate structures. The main issue still being debated in the industry is whether data must be time stamped at the meter rather within the network itself (the CellNet technique). The specific concern is whether billing problems might arise from occasional data errors or data that are out of synch in real time. Solutions that offer on-site time-stamped data cost significantly more than those that stamp data on a network. Innovatec Corporation and ATL Metering Ltd. currently offer a mass-market full two-way solution.

3.3 Summary of Ancillary Services Technical Requirements

Table 3.1 summarizes the technical requirements described for the ancillary services in the preceding sections.

Table 3.1 Summary of Ancillary Services Technical Requirements

AS MARKETS TECHNICAL REQUIREMENTS	Regulation	Load Following	Spinning Reserve Frequency Response	Supplemental Reserve	Back-up Supply	Current Time-of-Use Tariffs Markets	Air- Conditioning Programs	Water Pumps Programs	Demand Relief Markets	Other Potential Markets
Remote Communication Device	• Response: 1-5 Minutes • Real-Time Protocols and Security • Satellite Interface • PSC Meeting • Other	Response: 10-30 Minutes	Response: 0.5-10 Minutes	Response: 10-30 Minutes	Response: 30-60 Minutes		Response: 30-60 Minutes	Response - 30-60 Minutes		
Data Communication System	• Redundant with 99.9% Availability • ICCP • Control Data Protocol	Redundant with 99.9% Availability ICCP Protocol	Redundant with 99.9% Availability ICCP Protocol	Redundant with 99.7% Availability Protocol ????	Redundant with 99.7% Availability Protocol ???		Redundant with 99.7% Availability Protocol	Redundant with 99.7% Availability Protocol		
Master Control Computer System	• Redundant with 99.9% Availability • Real-Time Performance for Data Acquisition and Control Algorithms • User Friendly • Real-Time Support • Real-Time Database • Other	Redundant with 99.9% Availability	Redundant with 99.9% Availability	Redundant with 99.7% Availability	Redundant with 99.7% Availability		?	?		
Metering System	• Events Data-Start Recording Hardware • SSID Meeting • Other ?????						Yes	Yes		
Billing System	• Events Data-Start Recording Software and Applications • SSID Meting • Other						Yes	Yes		
Supplier Control Error Calculation Infrastructure	• Yes	Yes	Yes	Yes	Yes		No	No		
Type of Aggregation	• Probability for 98% percent availability 100% of the time	Probability for 100% percent availability, 100% of the time	Probability for 100% percent availability, 100% of the time							

4. Identification, Assessment, and Availability of Advanced Load Control Technologies

We divide the load-control technologies discussed in this section into two categories: those based on a wired communications medium and those based on a wireless medium. These two categories are further broken down into telephone-based, distribution-line, and broadband communications solutions. Key features, functions, and characteristics are outlined for 12 specific technologies.

Section 3 focused exclusively on the one-way, radio-based load-control technology that currently dominates the national market. In this section, we address more sophisticated, global technologies and systems. Most of these systems are not designed to deliver direct load-control services although some can be configured to do so. We describe these systems to demonstrate that numerous solutions already exist that can address the TOU and RTP needs of the electricity market. As noted earlier, some of these systems are sufficiently sophisticated that, in addition to providing price signals, they can also take action in response to load conditions.

4.1 Load Control Technologies that Utilize Wired Communications Infrastructure

The load control technologies that use a wired communications infrastructure described below are telephone-based solutions, distribution line communications, and broadband communications. For each types of system, the key features, functions supported, and benefits to the utility are described as well as products offered by specific companies.

4.1.1 Telephone-Based Solutions

The public, switched telephone network (PSTN) is the foundation for all voice and data communications and will likely remain so for many years to come. Copper wires generally create local loops that connect end users directly to the telephone company central office. Local loops have evolved to include fiber-optic cable interfaces at intermediate points where the system has been expanded to accommodate increased voice and data traffic. The "switched" portion of the communications system is at central offices where system capabilities are adjusted on an as-needed basis. Long-distance connections are routed through a hierarchy of central offices, high-speed trunk lines that connect these offices, and large tandem offices that interface with the Inter Exchange Carrier (IXC), which handles the long-distance traffic between Local Access and Transport Areas (LATAs). Competitive Access Providers (CAPs) provide networks that bypass local telephone company circuits. Voice and data traffic on CAP circuits go directly to the IXC.

Utility communications systems that use the data circuits of the PSTN data circuits must accommodate the design criteria of a network designed primarily for voice traffic:

- PSTN voice channels provide a bandwidth between 300 and 3,300 Hz. All data traffic must travel within this bandwidth. Data throughput is limited by the available bandwidth, not by the physics of copper wire.
- With the application of very sophisticated modulation techniques, data rates of up to 56 kbps are common today, but the laws of physics limit the possibility of increasing these rates.

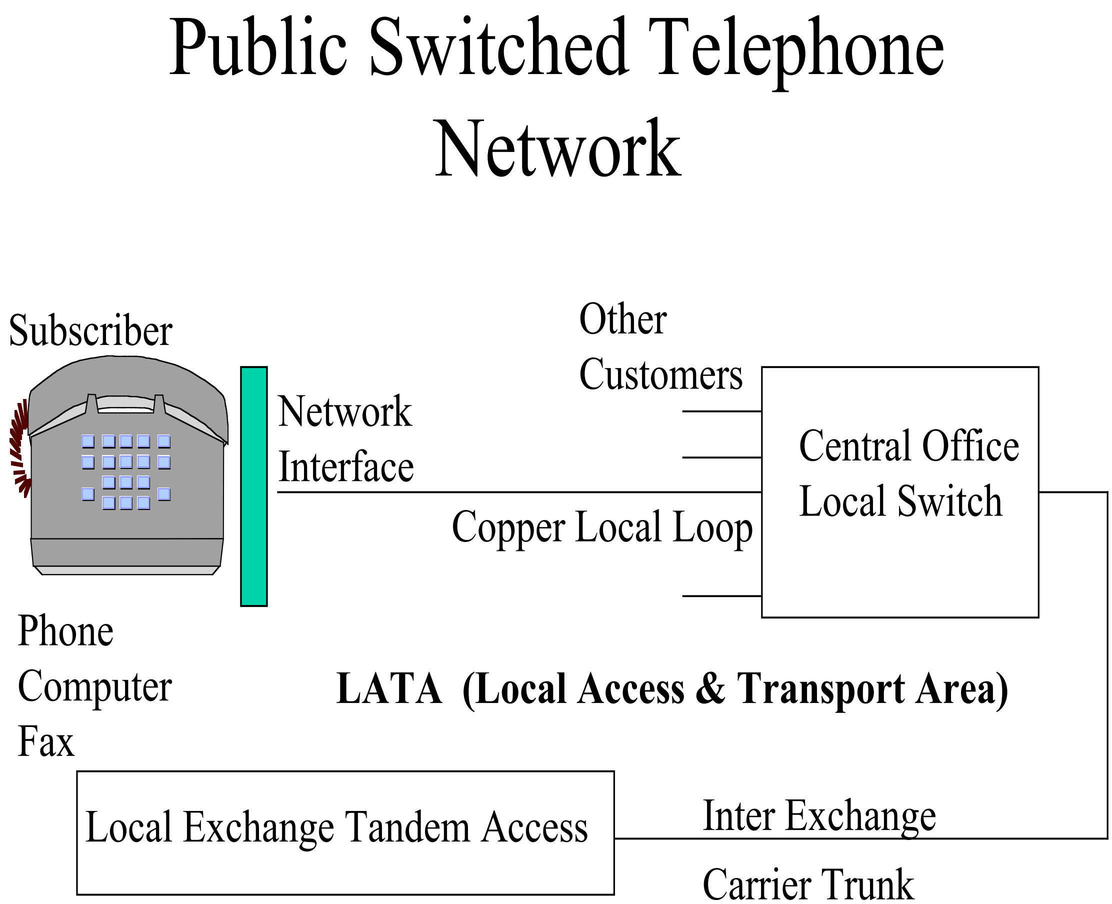

Figure 4.1 System Diagram of the PSTN

4.1.1.1 ABB / ICS (Integrated Communication Systems)

ABB / ICS's product is known as the TRANSTEXT Advanced Energy Management (AEM) system. The system monitors energy using a PSTN communications link with the end-use customer.

A CEBus-compliant LAN establishes the connection to a customer's thermostat, water heater, pool pump if applicable, and electric meter. The communications "gateway" also supports a wireless link to the outside world so that unscheduled downstream information can be downloaded to the customer site. Although the AEM system is available, ABB is not actively marketing it at this time.

The system supports the following functions:

- remote meter reading
- load control (HVAC, water heater, pool pump, etc.)
- TOU Rates

The major system components are:

- Transtext System Manager (software operating system)
  -Used at the utility to send and receive electricity price, usage, and billing information

- Transtext Thermostat
  -Provides customer interface for price, usage, cost and billing data, and programming capability for HVAC system, water heater, pool pumps, etc.

- Transtext Controller
  -Operates HVAC, water heater, pool pump, and thermostat

- Major Appliance Relay
  -Controls power to water heater and pool pump

- Com Set 4000
  -Communications Gateway and interface between wide-area network (WAN -- PSTN and wireless broadcast) and the LAN (CEBus power-line carrier)

- Electric Meter
  -ABB Alpha-based meter for electricity usage data

The benefits to the utility of this system include:

- Improved load management because system permits up to four pricing levels for TOU / RTP load control.
- Better product pricing because system allows flexible rate design.
- Improved system load shapes because customers have clear incentive to shift electricity usage patterns.
- Increased operating efficiencies because of improved load factors.
- Deferred system capacity additions because of reduced system peak demand.
- Increased customer satisfaction because of improved convenience, choice, control, and value.
- Improved marketing research/programs.
- Improved system forecasting.
- Improved ability to monitor program performance.
- Improved ability to identify new business opportunities, strengthen competitive position, retain customer market share, and increase market share.

4.1.12 eLutions

eLutions is an international energy information solutions company created by a joint venture between two industry leaders, Invensys Building Systems (IBS) and Engage Networks. eLutions offers web-based energy management software, internet-enabled data acquisition hardware, and installation services. eLutions services include real-time energy monitoring. Using the internet, customers can monitor energy at the moment it is consumed, anywhere in the world. This ability allows customers to analyze and negotiate rates and manage load curtailment, aggregation, and usage, among other things. eLutions Support and Energy Partnership (SEP) Bureau offers comprehensive facility audits, deregulated and regulated rate tariff negotiations, comparative rate analysis, co-generation monitoring and management, curtailment management, real-time pricing tariff management, and many other value-added services.

One eLutions product is Interlane Systems. The residential version is Interlane Home Manager, and the commercial and industrial versions are labeled PM6000 and PM4000. These systems currently use the PSTN / Commercial Paging for wide-area access and CEBus and X10 for the LAN. The customer interface is accomplished using a local PC.

The heart of the Interlane system is the Interactive Control Unit (ICU), a 386 industrial computer located at the customer's meter, which creates an interface between the WAN (PSTN) and the LAN (CEBus / X10 power-line carrier) communications network. As mentioned previously, the ICU also supports the X-10 two-way power-line carrier protocol.

Measuring modules are attached to individual circuits and transmit power quality information via power-line carrier to the ICU. A power-line modem (installed on the customer's PC) and Interlane software are used to communicate with the ICU.

This system supports the following functions:
- AMR.
- Remote services disconnect/reconnect.
- Power-quality monitoring.
- Tamper detection.
- Load management.
- Real-time pricing.
- Internet access.
- Interactive video - via optional WAN interfaces.
- Two-way paging.

The benefits to the utility of this system include:
- Reduces operating costs and improves electricity system management, control, and monitoring by:
- load shaping based on variable pricing
- emergency load shedding
- AMR
- remote connect and disconnect
- power quality monitoring
- remote tamper detect
- Builds customer loyalty by providing:
- value-added energy information
- ability to manage consumption
- access to usage patterns and cost

- Creates potential for new revenue through:
- collaboration with other service providers
- flexibility to deploy new customer services
- cost-effective addition of interactive services

4.1.1.3 MainStreet Networks

MainStreet Networks is an Internet Gateway Service Provider (IGSP) that partners with utilities to put entire homes and their devices on the internet. Utilities purchase and deploy MainStreet Networks services, based on the MainStreet Internet Gateway, and offer these co-branded e-services to customers. They manage the gateways, operate the network, and provide comprehensive marketing and support. MainStreet Networks open-architecture MainStreet internet gateway system transforms the customer's electricity meter into an internet connection that can deliver and manage load control services. The MainStreet Internet Gateway platform integrates the public broadband network (telephone, cable, or wireless) with the home narrowband network (telephone wiring, power-line carrier, or radio frequency link). MainStreet Networks system components include:

- MainStreet Internet Gateway - A communications-neutral network computer residing at the utility meter and providing processing, communications, and control resources to support applications, store information, and control and protect devices.

- In-home displays – A family of always-on, flat-panel displays with touch-screen navigation.

- Network Operations Center - A secure, redundant centralized network and database management system that enables utilities to deliver e-services to customers.

This system supports the following functions:

Residential Utility Services is monitoring and meter data collection service enabled by installing a MainStreet Internet Gateway at a residence. This service is remotely managed and operated from MainStreet's Network Operations Center (NOC). Through the NOC, MainStreet provides partnering utilities with electricity, gas, and water consumption data in a format compatible with each utility's billing system.

This system offers utilities the following operational benefits:
- Lower meter reading costs
- Flexible/aggregated billing
- Fewer estimated reads and rereads
- Improved operational efficiency
- Quicker response to power outages and reduced restoration time and costs

This system offers utilities the following strategic benefits:
- Positions partnering utilities to remain sustainable in emerging deregulated electricity industry
- Enhances customer satisfaction and loyalty

- Permits turnkey outsource service delivery
- Requires no investment in back-office computer equipment
- Requires no software or hardware licensing fees
- Does not require hiring of technology experts
- Offers guaranteed services and performance

Residential Utility Services offers a base level of service and multiple options to meet specific operational requirements of partnering utilities.

Residential Utility Basic Service includes:
- Monthly electricity consumption readings
- Tamper notification

Residential Utility Advanced Service includes
- Power outage/restoration notification
- Ancillary meter reads (gas, water, propane)
- Load profile (15, 30, and 60 minute)
- Time of use
- Physical remote connect/disconnect
- On-demand reads

4.1.1.4 Teldata Solutions

Teldata Solutions is a wholly owned subsidiary of myutility, formally owned by National Grid Group. The Teldata system offers a Meter Interface Unit (MIU) that can read all types of revenue meters – electricity, gas and water. Interface is accomplished via either a dial-inbound or dial-outbound "plain old telephone service" connection. The dial-inbound versions are powered from the telephone network. The dial-outbound units utilize the standard Subscriber Line Access Controller, located at the telephone company central office and connected to the utility's CIS. All dial- inbound systems have off- hook detection capability.

This system is primarily intended for AMR and is not intended to provide a true gateway into the customer's premises. Several system trials are under way using a file server connected to the internet for customer access. The data available include all typical use information as well as graphics. These systems are only sold to utilities, but the AMR data are available to commercial and industrial end users, aggregators, power marketers, etc.

The link between the MIU and on-site meters is either hardwired or RF. In 1998 Teldata Solutions acquired First Point Services, one of the first companies to offer web-based energy information access capability.

Teldata Solutions' product includes the following components and features:

- Teldata Tds-4 (four port) & Tds-2 (two port) is a multi port data-logger and dial-inbound unit with static and dynamic off-hook detection. The device operates on a customer's phone line with no inconvenience to the customer. The device can also be polled on demand with a multiring or tone alert. The device reads and stores at user-selected intervals (up to 31 days of 15-min.-interval readings) and calls in at user-selected times. The units requires nominal AC power or battery (10-year life). Teldata's Multi-Host feature enables the device to be shared by competing utilities while securing each utilities data to separate host computers (one per port).

The device is compatible with most pulse-output and three-wire encoded meters. Other features include peak demand calculation, power outage and restoration reporting, tamper detection, pulse or tone dialing, battery back-up, and a call retry algorithm.

- Teldata Retrofit Optical Scanner is an optically based single-phase electricity meter pulser. The device mounts under the rotating disk of most popular residential and small commercial single-phase meters including GE I-70, ABB AB-1, Landis & Gyr MS, and Schlumberger J4S and J5S.

- Teldata ShortHop RF technology enables communication with meters not located near a telephone line. ShortHop works with all meter types and can deliver data to multiple channels for each data recorder.

- Web-based Energy Information Services

Teldata Solutions is a pioneer in making meter data usage information available to customers through a secure website. Teldata web-based services are secure and may be branded to the utility. This web-based service gives the utility's commercial and industrial customers rapid, secure access to their usage data and provides customers and the utility with customizable reports.

Teldata Solutions' units have been primarily deployed in Asia. A single unit costs $50, or $150 with whole-house disconnect / telephone communications. The disconnect meter (under the glass, 200A) is relatively inexpensive at $150 (these units typically cost about $250).
Teldata Solutions' product would be especially effective if the company adds a wireless interface (see Innovatec, Section 4.2.1.2) that works with several technologies, i.e. Internet Telemetry Corporation, etc.

Standard features: of the Teldata Solutions' MIU include:

- Built-in modem that communicates to and from the meter for remote data access and configuration
- Data access arrangement for direct AMR
- Rolling and block demand calculations for active and reactive power
- Four TOU tariff periods with custom weeks, day schedules, and exception days
- 16 recording channels with up to 210 days of recording. Up to 1,050 days when using three channels
- One- to 60-minute load profiles
- Individual phase currents (calculated)
- Multi-symbol LCD with 75mm x 35mm active display area
- 200-amp rating, ANSI socket mounting
- Infrared optical LED pulse output for accuracy verification
- Back-up battery saves all data and settings during power outages

- Diagnostic information for tracking meter operation
- Data transmission accuracy ensured using CRC-16
- Dual level encryption provides data security
- Multiple password levels for users and administrator provide management security
- Automatic recording of power surges, sags, and outages
- Alarms for meter operating variances
- Additional Optional Features: Cellular, Cellular Digital Packet Data (CDPD), and paging communications options

This telephone-based solution can also support some wireless WANs. The price of this product is very competitive compared to the prices of alternative solutions.

4.1.2 Distribution Line Communications

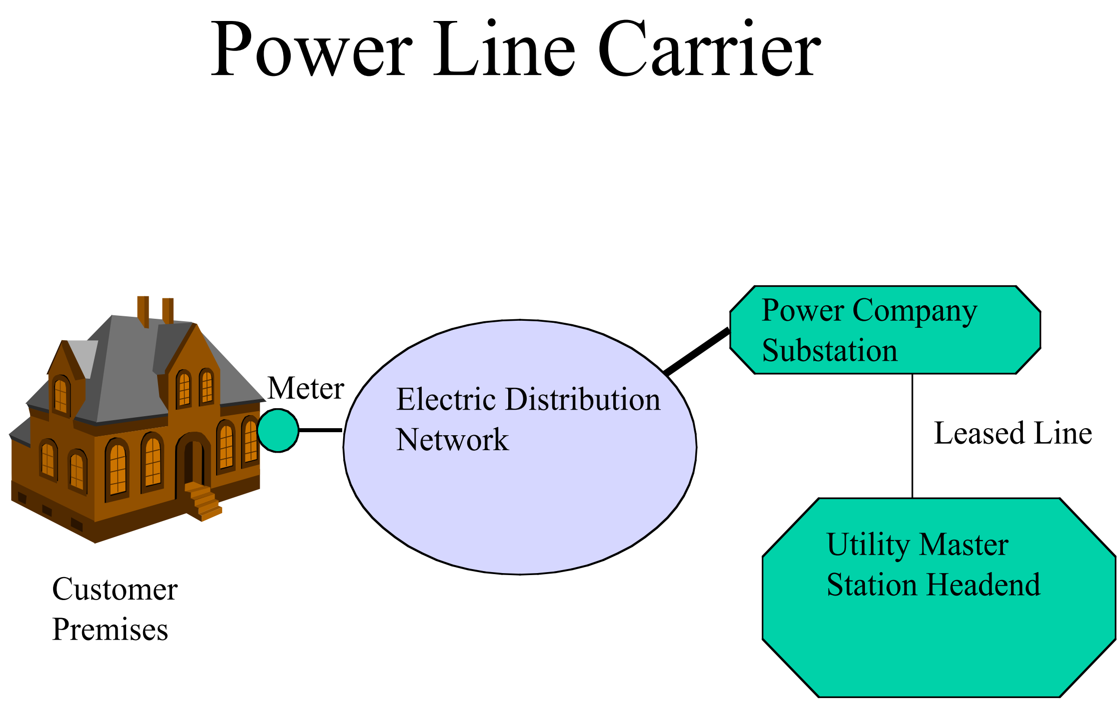

Figure 4.2 Power-line Carrier System Diagram

Power-line carrier systems transmit very low-frequency signals over utility transmission or distribution lines. Most applications are for slow-speed data and protective relaying. The typical frequency is between five and 100 kHz. Utilities have tried for decades to deploy these systems successfully. One-way applications have proven the most effective; two-way applications have been be a major challenge. Two-way PLC systems are available commercially.

A variant of traditional PLC technology utilizes the 60-Hz frequency. Equipment located at the utility computer center controls the system operation, which is based on a unique method of inbound and outbound signal modulation . Because the system utilizes a 60-Hz signal, data relay is very slow. One major advantage of the 60-Hz frequency is that no major network (distribution line) modifications should be necessary to accommodate this technology.

4.1.2.1 Distribution Control Systems, Inc. (DCSI)

The Two-Way Automatic Communication System (TWACS) is a power-line communication system invented and patented in the late 1970s for use primarily by electric and combination utilities for AMR, load management, and other related functions.

The communication technology utilized by the DCSI System-10 is the patented TWACS technique of frequency modulation for two-way communication on the power line. Outbound messages – from substation to the end user – are transmitted by modulating the voltage wave shape near the zero crossover point; binary ones and zeros are indicated simply by the location of the modulation. Inbound signaling – from the end user back to the substation – is achieved by applying a unique pattern of current pulses in the field devices; those pulses are detected in the substation. Both techniques produce very small changes to the existing wave shapes, imperceptible to any equipment except DCSI's highly sensitive receiving devices.

TWACS is a fully integrated system that could implement load management, load surveying, AMR, and automated distribution.
This system supports the following functions:

Integrated Metering Transponder family:
- On-request meter reads (meter data retrieved in 20 seconds or faster).
- Tamper, diagnostic, and outage detection and reporting.
- Non-volatile electronic memory -- no batteries to fail or wear out.
- Built-in 15-minute peak-demand measurement with remote reset.
- Individual, unique serial number addressing mode.
- Group addressing modes for high system throughput.
- System-level time synchronization for profiling, TOU metering, and real-time pricing.
- Direct, two-way access to the meter for "hard" service disconnect, demand reset, and download of parameters and schedules.
- Complete under-the-glass solution for single-phase watt-hour meters (Landis & Gyr MS and MX, ABB D4, D5 and AB-1, Schlumberger J4 and J5, General Electric I70, and GE Canada I70, Schlumberger’s planned K2).
- Water and gas AMR capability using a wide range of interface devices.
- Approved for billing by Measurement Canada, Legal Metrology Branch.
- TOU Metering.
- Load Management.
- Distribution Automation.

The benefits to the utility of this system are limited to the applications implemented. At this time, TWACS is primarily a targeted (AMR, load management) application system. The current architecture does not support creation of a conventional LAN (i.e. CEBus, LonWorks, etc.). Recent discussions with DCSI have indicated a willingness to partner with utilities to develop a gateway / LAN based system to implement functions that are not implemented directly with the TWACS communications system.

4.1.2.2 Cannon Technologies / EMETCON

EMETCON is a modular automated communications system that utilizes conventional power-line carrier techniques. A relatively high frequency (8-15 kHz) is injected into the electricity system distribution network at the distribution substation. Because of the frequency employed, bypass filters must be deployed to keep the signals from being shunted to ground at capacitor banks.

The main system components are a master station controller located at the utility office, a carrier control unit/primary coupling assembly located at the substation to act as the interface with the distribution network, the electricity distribution network, and the meter and transponder equipment located on the customer's premises.

EMETCON'S Distribution Line Carrier is a mature communications technology that has been used by nearly 200 utilities, some for up to 15 years. The system uses a proprietary packet-based protocol, which supports the use of store and forward repeaters and has allowed it to become the most widely used form of direct load control with concise, fast, and secure communication. A simple one-way broadcast load-control command takes approximately one second to transmit. A two-way communication takes about four seconds to complete from the master station (using dedicated phone line). If a repeater is included in the routing, the time is a few seconds longer. Data packets are small and typically carry only a few data points at a time. The end-point devices cannot initiate a communication without being polled by the Carrier Control Unit (CCU), so all communication is very tightly controlled and routed. The computer handles routing and retries for failed communications.

A major benefit of this type of distribution line carrier approach is its utilization of a single channel for both two-way and one-way broadcast communications. The resulting "network" is on line full time for quick access. No license is required for installation, and the system is utility owned.

Figure 4.2 shows the basic components of a distribution line carrier injection point. This pole-mounted setup includes a single high-voltage coupling; however, a single CCU can support up to eight couplings at different voltages. A sub with two buses, one at 13.8 kV and one at 24.9 kV, is an example.

Starting from the bottom, a dedicated phone circuit connects the CCU to the master station computer at the utility office. This connection could use any form of two-way communication, including radio, dedicated fiber, etc. The CCU is housed in a weatherproof cabinet and can be mounted outdoors or indoors. It contains card slots much like those of a personal computer. Component cards are inserted into these slots and can be swapped for troubleshooting.

The CCU transmits a digital signal in the form of a sine wave at 9.6 or 12.5 kHz. This frequency is induced onto the copper distribution line through the Signal Coupling Unit (SCU), a small gray box fastened to the capacitor rack. The coupling capacitors act as a "high-voltage gateway" for this signal, with very high voltage on the high-side bushing and low voltages on the ground side. The grounding conductor of the capacitor bank is passed through the SCU, and the data packet signal is induced onto this ground through an isolation transformer in the SCU. The EMETCON signal then propagates down the line omni-directionally.

Receivers and transponders located out on the distribution feeder "hear" this data packet and respond. Repeaters like the one shown in Figure 4.2 will digitally repeat the data packets when they are part of the routing. The CCU also includes a receiver card that hears the responses coming back from the polled devices or repeaters.

This system supports the following functions:

- Automated Distribution
- AMR
- Load Management
- TOU Metering
- On-demand reads
- Remote Connect/Disconnect
- Load Surveys

4.1.3 Broadband Communications Solutions

A hybrid fiber-optic and coaxial (HFC) network results when most of a cable TV network has been upgraded to fiber-optic cable but a last network node remains in coaxial cable, usually serving 250 to 500 homes. By upgrading its one-way amplifiers to two-way, the cable system can provide a return link to the head end. The typical bandwidth available in these HFC networks is 750 MHz; some go as high as 1 GHz. The frequency range for upstream (return path to the head end) transmissions is usually allocated to the five to 42 MHz portion of the available spectrum, and downstream transmissions occupy the balance of the available bandwidth. The portion of the base band between 54 and 450 MHz is generally left alone so that the system can continue broadcasting the existing analog TV channels. Per IEEE 802.14, the upstream spectrum will be broken into channels from a few hundred kHz to approximately 1 MHz, and the downstream spectrum into six-MHz channels in the 54-MHz to 450-MHz portion of the baseband and one-MHz in the 450- to 750-MHz portion. Utilization of modulation techniques such as Quadrature Phase Shift Keying (QPSK) allows data rates of approximately two to three Mbps to be supported on the upstream channels. The downstream channels utilize 64-quadrature amplitude modulation (QAM) and can deliver data rates of approximately 30 Mbps. To take advantage of this data capability, the end-use customer must employ the appropriate cable modem. The IEEE 802.14 working group is finishing the development of the appropriate industry standards for these modems.

The most significant characteristic that separates an HFC network from its CATV forerunners is the ability to provide full-duplex (simultaneous two-way) high-bandwidth connections to the end user. These systems have evolved from a simple CATV system to a full-blown, broadband, bi-directional communications system. An HFC network is “always on” because of the packet-switched nature of the connection with the ISP. As soon as the user turns on his/her PC, the ISP sets up a new internet connection.

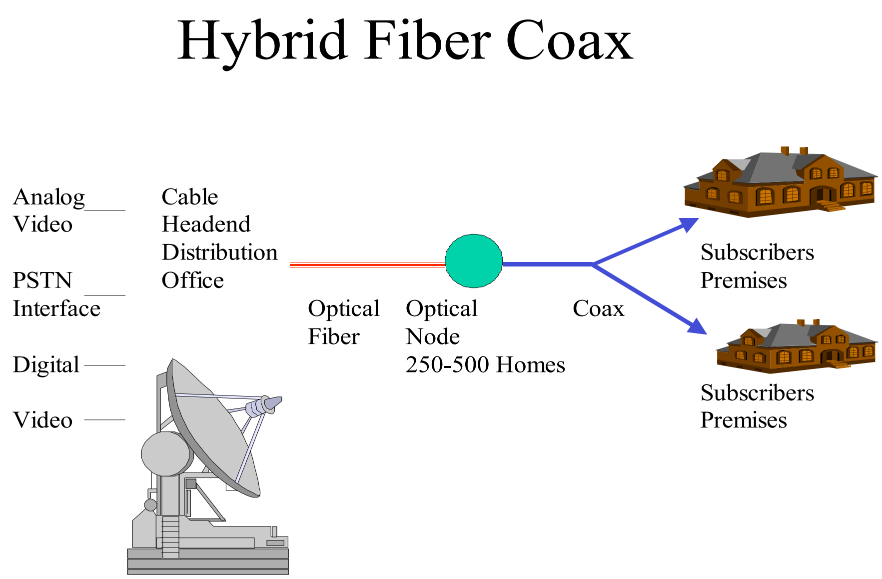

Figure 4.3 System Diagram for an HFC Network

4.1.3.2 Comverge Technologies, Inc.
- MAINGATE Utility Automation System

Comverge Technologies, Inc. purchased the Scientific Atlanta (SA) Control Systems Division in 1999. The old SA Control Systems Division (which eventually merged with the SA Broadband Group) was a premier supplier of load management systems for electric utilities. The merger of that division with the Broadband Group resulted in the development of a utility-focused application of HFC broadband infrastructures. The product is the MAINGATE Utility Automation System. It uses an existing cable TV HFC system for the WAN link back to the utility master station equipment. The MAINGATE system includes a "gateway" at the home, which provides the interface between the WAN and the LAN on the customer premises. The LAN may be CEBus, LonWorks, etc. The full duplex data rate to the end user will be 128 Kbps utilizing one MHz of HFC system bandwidth. Comverge intends to support multiple WAN interfaces, including satellite, cellular, and hybrid systems. A new project has been announced that uses broadcast radio (VHF paging) for outbound initialization, and the PSTN for remote inbound communications.

The system supports the following functions:
- AMR
- Customer-Controlled Load Management
- Real-Time Pricing
- Home Automation and Servicing
- Customer Messaging
- Remote Connect/Disconnect
- Outage Verification
- Tamper Detection

The primary benefits to the utility of this system are cost and system scaleability/flexibility. As mentioned previously, a true LAN/WAN system infrastructure in this price range is unique in the industry. The ability to scale up to additional applications over time creates a very "future proof" system.

Comverge Technologies Inc. in 1998 licensed the technical information, software, and equipment from the Lucent Technologies Customer Connection for Utilities and an associated pending patent. Lucent Technologies, formally part of American Telephone and Telegraph (AT&T), consists of Bell Labs, and Network Systems, Microelectronics, Multimedia Products Group and Business Communication Systems. The Comverge solution for electric utility customer communications, originally known as the Lucent Customer Connection, is now known as Comverge Customer Connection. The initial commercial product provided a WAN/LAN interface utilizing an HFC WAN and a CEBus LAN on the customer premises (secondary of the electric system distribution transformer). The Comverge solution in intended to provide a platform for full-service customer solutions for electric utilities.

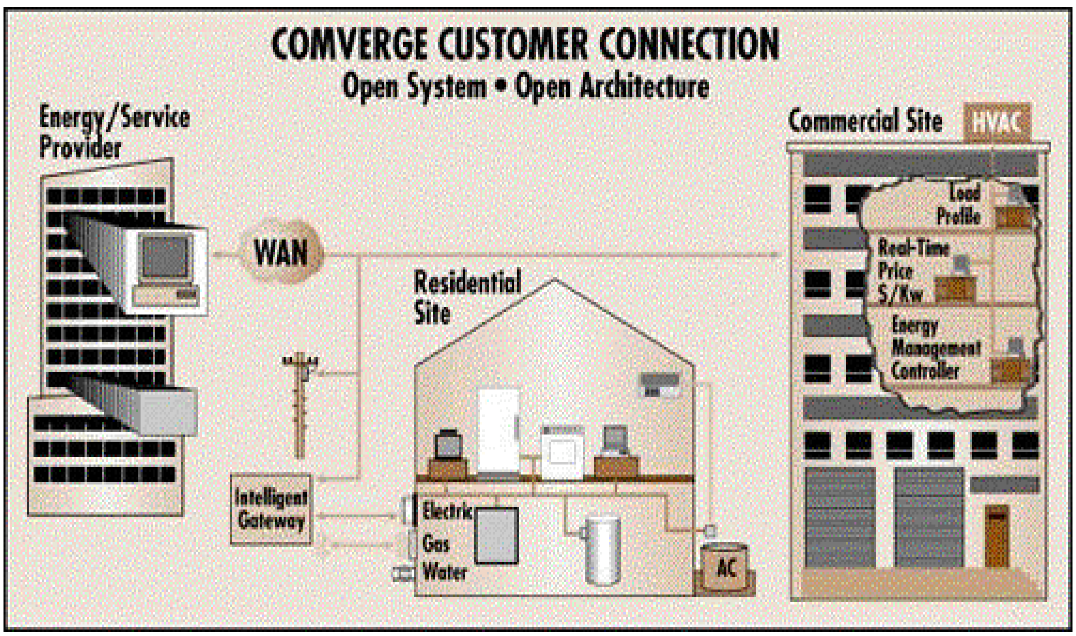

Figure 4.4 Comverge Customer Connection System Diagram

The Comverge Distributed Connection is a Cellular Digital Packet Data (CDPD) meter-reading system. Comverge Technologies provides a cost-effective means of using the high-quality, widely deployed CDPD network to read interval data from commercial and industrial (C&I) customers. Its initial cost is low, it is easy to install, and it has the lowest operating cost of any communications system. The system provides rapid deployment for geographically dispersed customers.

The turnkey Comverge system includes meter interfaces for electronic or pulse output meters and the comprehensive, scalable software to control and operate the system. In addition, the customer can access data via an internet web page. Comverge also provides options for using CEBus (EIA-600) power-line interfaces to hub multiple meters within a location or to control devices on the power line. This CEBus option enables cost-effective demand control, reporting of real-time energy prices, interval metering for load profiling, and other value-added services.

The system supports the following functions:
- Immediate AMR
- Outage Detection
- Service Connect/Disconnect
- Real-Time Load Management
- Distribution Automation
- Tamper Detection
- Power-Quality Monitoring
- Security
- RTP
- Customer-Controlled Load Management
- Appliance Monitoring

4.1.3.3 muNet

muNet's internet metering and communication gateway technology enables utilities and service companies to use residential and commercial customer data to enhance service to these customers. From an open standard gateway device located at the electricity meter, muNet offers secure two-way communication with customer sites for electric, gas, water, and broadband utilities as well as providers of other home services, such as energy management and appliance maintenance. muNet's innovative product line leverages three trends - internet availability, utility restructuring, and home networking. In addition to their potential for use by multiple utilities and service providers, muNet's open architecture systems offer significant cost and performance advantages over existing systems requiring proprietary networks.

Since 1997, muNet has been developing WebGate™, an internet solution that connects electricity meters directly to the Utility's Customer Information System. WebGate integrates the customer meter and the utility's CIS using AMR, enabling Remote Device Control and providing customers access to both historical and instantaneous data directly from their meters. Direct two-way communication with customers through the meter also creates the opportunity for the utility to provide programs and services such as TOU and RTP, demand load management, and energy management services. muNet's connection between the customer, the meter, and the utility is established using the internet, which avoids the problems associated with traditional AMR systems. WebGate™ offers full two-way AMR communication without the need to deploy a proprietary network or expensive head-end control hardware.

To make WebGate™ a broad-based solution that will accommodate the changing utility market place, muNet has committed its R&D to a standards-based open architecture development path, which will give systems the flexibility to grow and expand in response to future needs.

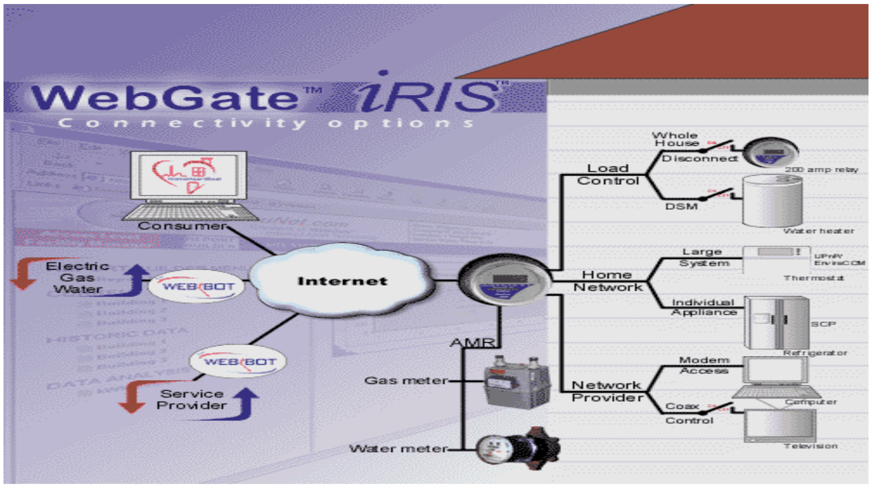

Figure 4.5 muNet's Webgate System Diagram

The current system supports broadband interface options such as CATV / HFC, DSL, and Ethernet. The meter output is standard Ethernet, which interfaces with a cable or DSL modem. A standard telephone interface is not currently available. The meter becomes its own website for internet access through any standard browser.

The **WebGate™ iRIS** can provide information to utilities and customers as soon as the site unit is installed and an internet connection is established. The unit can acquire pulse output from meters other than electricity (gas, water) on site using two external channels. The site unit can also access and control other devices/systems on site. Examples of applications of this connectivity are: whole- house disconnect or load restriction, remote load shedding by means of thermostat control, and remote appliance diagnostics. The **WebGate™ iRIS** gateway uses standards-based open-architecture protocols, including XML. The in-house LAN is based on a wireless (902 to 928 MHz) protocol using a Microsoft-supported standard for open systems. The hard-disconnect option (200 amp) is implemented with a hard-wired interface between the meter and the disconnect relay. Retrofit is an option (under the glass) for legacy electromechanical meters.

4.2 Load Control Technologies that Primarily Utilize Wireless Communications Infrastructure

The subsections below describe load control technologies that rely on wireless communications: unlicensed spread spectrum applications and private fixed cellular networks. The functions supported and benefits of these systems are listed, and products offered by specific companies are described.

4.2.1 Unlicensed Spread Spectrum

Most applications of unlicensed spread spectrum are for wireless LANs. However, one manufacturer (Metricom) has implemented a regional network using this technology. The system operates in the 902-928 MHz unlicensed area of the radio spectrum and uses intelligent radios to create a multipoint-to-multipoint wireless data network intended for electric, water, oil, and gas utility applications. The system operates at a 100-Kbps raw channel throughput [compared to 19.2 Kbps for commercial packet radio systems (ARDIS)] with up to 28.8 Kbps actual throughput. Higher throughput might be possible in the future. This system uses Code Division Multiple Access to spread the signals over the allocated spectrum.

Two key issues associated with this type of system are:
- Unlicensed spectrum users are by definition burdened when there is co-channel interference.
- The system shares the spectrum with numerous consumer electronic devices.

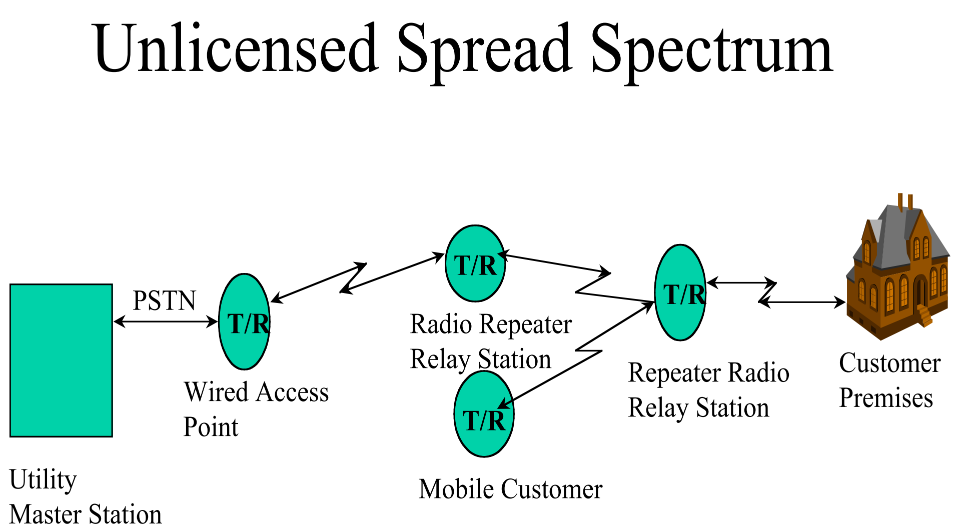

Figure 4.6 Unlicensed spread Spectrum System Diagram

4.2.1.1 Internet Telemetry Corporation (iTC*)*

Internet Telemetry Corporation is an information-gathering and processing service that transmits data through two-way proprietary wireless equipment known as the IMR Server, which is installed at a customer's premises. Originally a startup business unit of Williams Communications Group Inc., Internet Telemetry Service was founded in 1997 and is currently conducting system trials with national companies.

In iTC's system, Telemetry Interface Modules, mounted on meters and other devices to be monitored, gather and transmit data to a local IMR Server. The IMR Server forwards the data to the National Operating Center -- via a national WAN that includes wireless (SkyTel) and long-haul fiber systems interconnected by Williams' own asynchronous transfer mode (ATM) network. Data are recorded every 15 minutes and transmitted daily or whenever a significant event occurs on the network. Information gathered at the National Operating Center (in Tulsa OK) is processed, stored in databases, and routed to clients. Computer services also include energy usage analysis, billing packages, internet inquiry services, and a wide range of energy management services. In addition, the WinGate units can be used for numerous information-based applications, such as message delivery and monitoring.

This system supports the following functions:

- Monitoring of electric, gas, and water meters to efficiently manage deregulated energy sales.
- Monitoring and control of thermostats to support energy management systems.
- Monitoring and control of HVAC and lighting to reduce energy consumption.
- Monitoring of alarm sensors as back-up for telephone reporting .
- Distribution of electronic coupons into the home.
- Distribution of voice, computer, and multimedia data.

Typical system users are power utilities, energy providers/energy service companies, and national retail chains.

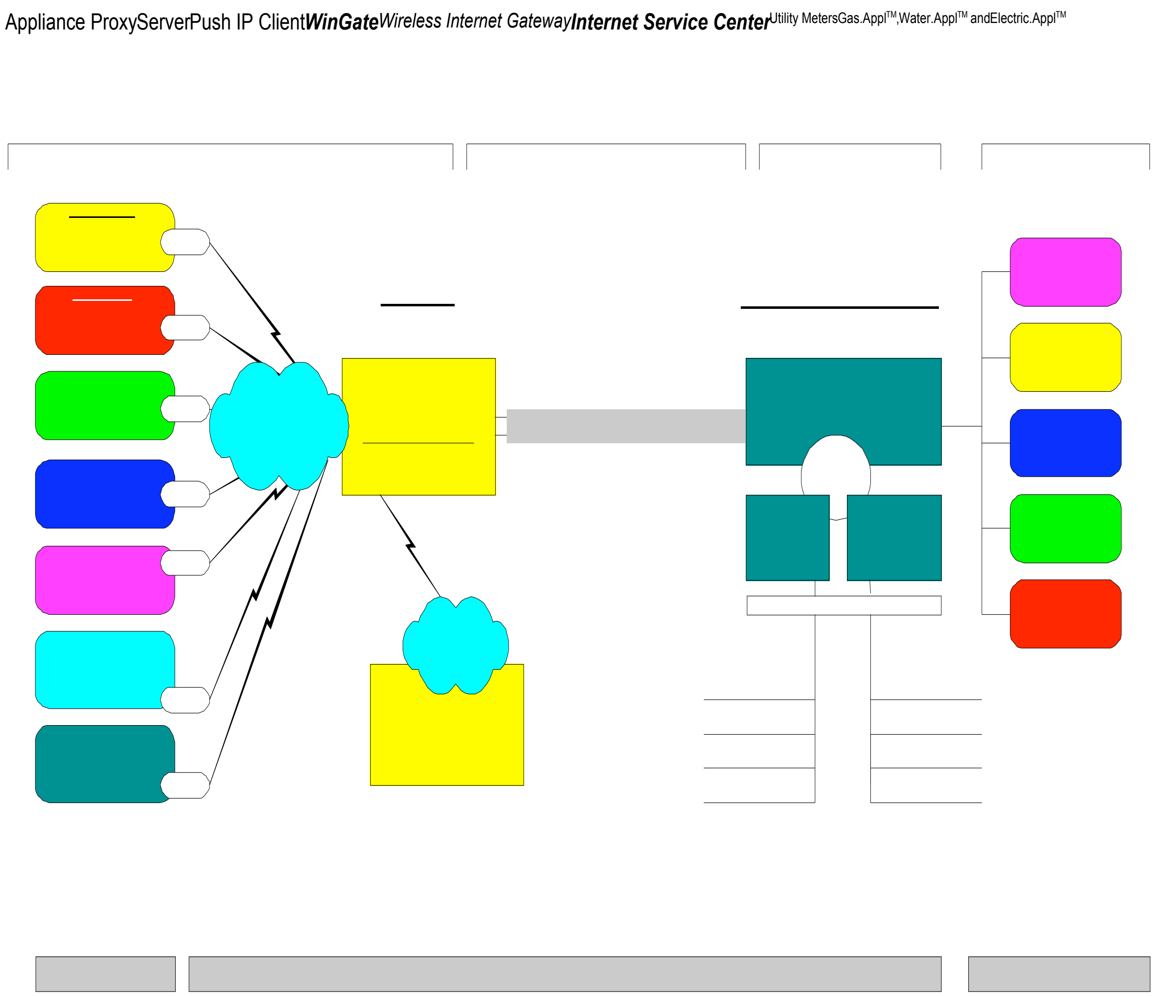

Figure 4.7 System Diagram

4.2.1.2 Innovatec Corporation

Innovatec's system is a true, 100-percent two-way system that does not require a secondary fixed cellular infrastructure like other systems described previously. This system uses an existing WAN that can be provided by numerous common carriers for the back-haul function.

Innovatec uses 900-MHz direct sequence spread spectrum to create a two-way LAN network that collects meter information and can support additional value-added services such as security, load management, environmental monitoring, etc. From a communications perspective, this system appears capable of implementing most if not all "narrowband" value-added customer services currently being considered by utilities.

The system gateway communicates with the 900-MHz transceivers and retransmits information to the utility using existing common-carrier networks. The amount of information that can be stored at the gateway or meter site is currently unknown. The gateway is normally pole mounted.

When multiple utilities (water, gas, etc.) use the system, the electricity meter can function as a repeater, which allows for a reduced power output and therefore a smaller drain on the batteries for each unit.

The Innovatec system is a very powerful composite solution. The most obvious concern is the cost per point, which is significantly higher than can be justified by most utilities for mass-market meter reading in today's world. Not only is the meter costly, but a utility must replace its existing meter inventory to use this system. This requirement would be a huge obstacle for most utilities.

System deployment valued at approximately $20 M is pending for SCANA corporation. Innovatec is targeting municipal markets because of the company's innovative water (pit set) solution for wet environments with a flat-surface-mount antenna for the pit lid. In time, Innovatec may be forced to develop a less expensive one-way solution for the mass market. There seems to be some consensus in the industry that the residential mass market will not demand the kind of rigorous data that can be delivered through full-blown two-way metering solutions.

Having a gateway for the first level of data retrieval is typical. If the gateway uses SkyTel as its WAN interface, it would closely replicate the iTC SkyTel (at least in the field).

The system architecture suggests that the system head end (NOC) would be maintained at the utility corporate office and that data are not routed over the internet through any kind of separate NOC. As a result, the system would not offer value-added web posting of data, etc.

4.2.1.3 Nexus Data

Nexus Data's system is currently primarily a one-way RF solution using direct-sequence spread spectrum with data collectors mounted on communication towers to reduce infrastructure cost. It is an under-the-glass solution for the ABB electromechanical 1ø and Schlumberger 1ø Centron meters. The ABB solution includes the optical pulse initiator, which is an integral part of that circuit board. The Nexus Data transmitter reports actual register readings for the ABB or Centron as well as tamper detection (reverse meter rotation). A local handheld device is used to synchronize the meter register reading and transmitter at the time of installation for the ABB.

For the Centron, the Nexus system actually drives the meter register and therefore cannot be uncoordinated.

Typical cell size ranges from five to 10 miles. For a 3,000-square-mile service area, an estimated 70 to 80 receiver sites would be required. Each receiver/cell can support 86,400 time slots or meter readings per day. Each time slot is one minute, and each receiver supports two carrier frequencies. (Each carrier supports 43,200 one-minute time slots). The actual transmission time is 150 ms, so the probability of collisions is relatively low. The system also employs the "capture effect" to avoid collision problems, using three receivers to cover a particular area; each transmitter can be received by each receiver station. The system uses one-watt transmitters to increase range of meter transmitters (for electricity, water, and gas). The gas and water transmitters use lithium batteries that are supposed to last 10 years. The receiver base station antennas are typically 150 to 300 feet high. Time stamping takes place at the receiver server.

Two-way units for are being developed C&I customers to support synchronized time-stamped data for demand billing, service disconnect/reconnect, and TOU billing. The two-way system will not utilize the 900-MHz ISM band for downstream transmission. That link could be paging, either private or public. The most likely data retrieval method will be via the data port in the meter (RS 232) where the data are already stored. The company is prepared to provide the down link time synch needed by the meter and to perform the "billing read" function, which resets the register demand values. Neither solution is contemplated for "high end" C&I customers. It is currently anticipated that a dedicated link to those customers' sites would use technology such as the Siemens / SmartSynch / SkyTel solution. The company is not currently using its system for these customers because of the number of data that would be routed through the network.

The NOC for this system can be owned by the utility or outsourced to Nexus Data. Joint ownership options are also available. The NOC collects all of the data and routes them to the utility systems.

4.2.2 Private Fixed Cellular

The implementation of privately owned fixed cellular networks is very attractive to electric utilities interested in system automation that does not require the types of exotic applications that can be provided by more robust telecommunications options (HFC, FTTC, etc.). Privately owned fixed cellular networks are offered primarily by ITRON (Genesis), Whisper, and CellNet Data Systems. CellNet uses the privately authorized 900-MHz Multiple Address Systems (MAS) frequency band for the back-haul portion of the system. ITRON has replaced its 900-MHz system with a 1.4-GHz network, which provides high-speed network for Distribution Automation as well as links to customers for basic energy management services. Whisper uses the 900-MHz unlicensed spectrum for the home link and the fist several hops of back haul. The rest of the back-haul network is provided by other telecommunications infrastructure. The last link in all of these networks – to the end user – operates in the unlicensed portion of the 900-MHz spectrum (902-928 MHz) and utilizes its own range of spread-spectrum techniques. This system is not currently designed for true gateway access to the home for interactive services, home automation, etc. because of limited data capacity. However, within the scope of traditional utility applications, the network provides more than adequate throughput capacity.

Private Fixed Cellular Networks

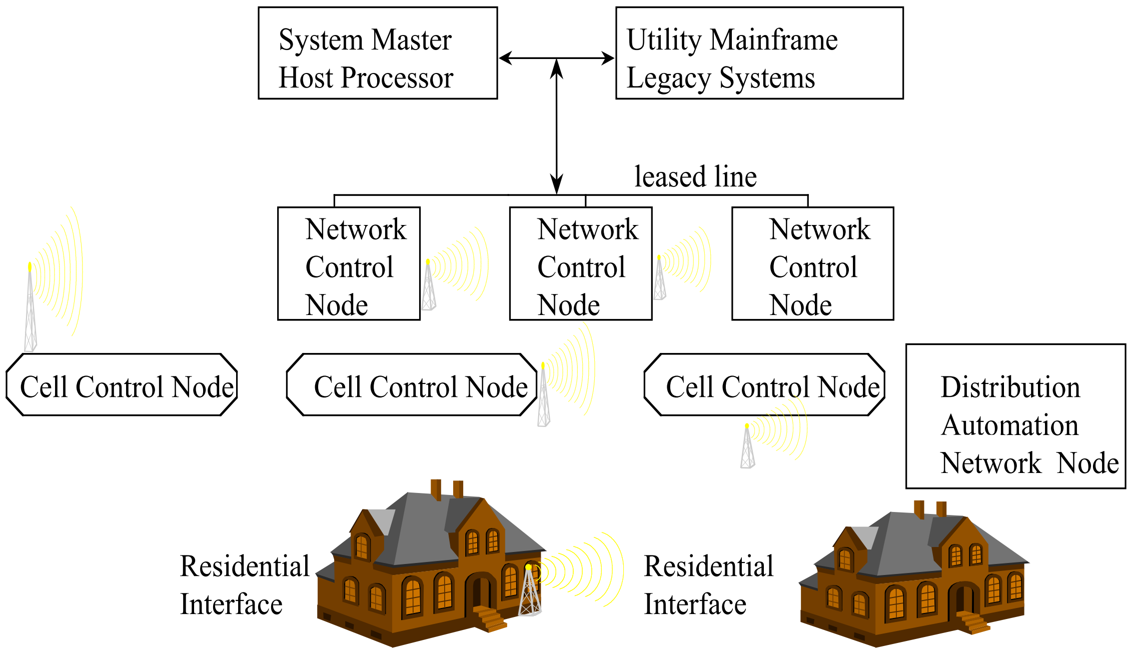

Figure 4.8 Private fixed Cellular Network System Diagram

4.2.2.1 Itron, Inc.

The Itron solution is an open architecture system designed to incorporate de facto industry standards to allow interoperable design. The system also provides transparent gateways to other communication infrastructures and applications. It supports incremental automation strategies that optimize technology investments and allows for the integration of existing utility communications and data processing infrastructures. The Genesis family of products provides a multimedia, multi-applications system solution for AMR, Distribution Automation, and demand-side management (DSM).

The Genesis system is built primarily around its licensed fixed cellular infrastructure combined with an unlicensed radio link to the meter. It can also interface with power-line carriers, telephone, and gateways to other industry standard networks. In addition, utilizing either hand-held or vehicle-mounted interrogation units supports off-site, mobile AMR.

The primary components of the fixed network are the meter module (ERT), the first data concentrator (Cell Control Unit), the second major network element (Network Control Node), and the Host Processor. The communications system for the back haul of the meter data utilizes an Itron nationwide-licensed frequency in the 1.4-GHz band. All ERTs operate in the unlicensed 902-928 MHz band.

A “Micro Network” is available that allows for precise network deployment. It currently supports the ERT family of products that report consumption. The capability to add demand reporting is currently being developed. A C&I network utilizing the Itron licensed 1.4-GHz frequencies has also been developed to replace a telephone line for C&I customers connected to the MV-90 host.

Figure 4.9 Elements of the Itron System

The Itron system supports the following functions:

- AMR (one-way & one-and-a-half-way)
- TOU
- Load Profile
- Virtual Service Connect / Disconnect
- Tamper Detection
- Outage Detection
- Leak Detection
- Scheduled / Unscheduled Meter Reads
- Group Load Profile
- Group TOU
- Consolidated Billing
- Demand (Fixed Network)

The utility benefits associated with Itron system deployment are tactical and strategic. The tactical benefits are direct reduction in the cost of traditional utility functions (AMR, etc.) and improved system efficiency (Distribution Automation). The strategic benefits may have more impact in the long run by preparing the utility for the developing competitive environment. However, the system by itself does not support a "gateway" interface to the home and as a result cannot offer the more sophisticated energy/customer services associated with that kind of capability.

4.2.2.2 CellNet Systems (Purchased by Schlumberger 5/2000)

CellNet systems offer a wireless direct data link between the utility and its customers. These systems utilize a typical fixed cellular structure consisting of small cells that link back to a network accumulator and finally to a host processor.

The microcell LAN provides the link to the electric meter [microcell controller – (MCC)]. This portion of the system operates in the unlicensed spectrum and incorporates spread spectrum technology. The cell is anchored by a Cell Master, which communicates with the MCC on licensed frequencies. It also connects back to the Master System Controller, which manages the entire system. The meter module is a transmit-only device that operates in the unlicensed portion of the spectrum and incorporates direct-sequence spread spectrum technology. The meter module mounts under the glass of the existing electric meter.

CellNet's marketing strategy is not based on the sale of the system hardware and software but instead on establishing long-term (20+-year) outsourcing contracts for applications that are purchased by individual utilities. CellNet will also market additional services (monitoring of vending machines, copiers, etc.) to non-utility companies.

The CellNet system supports the following functions:
- AMR (one-way)
- Distribution Automation
- TOU Metering
- RTP
- Real-Time Load Profiling
- Remote Service Connect / Disconnect
- Gateway to MV - 90
- Gateway to SCADA
- Outage Detection

The utility benefits from the CellNet system are primarily reduced system operating costs. Additional non-traditional services could also be purchased to implement strategic customer services. These services could also be targeted to generate additional cash flow for the utility.

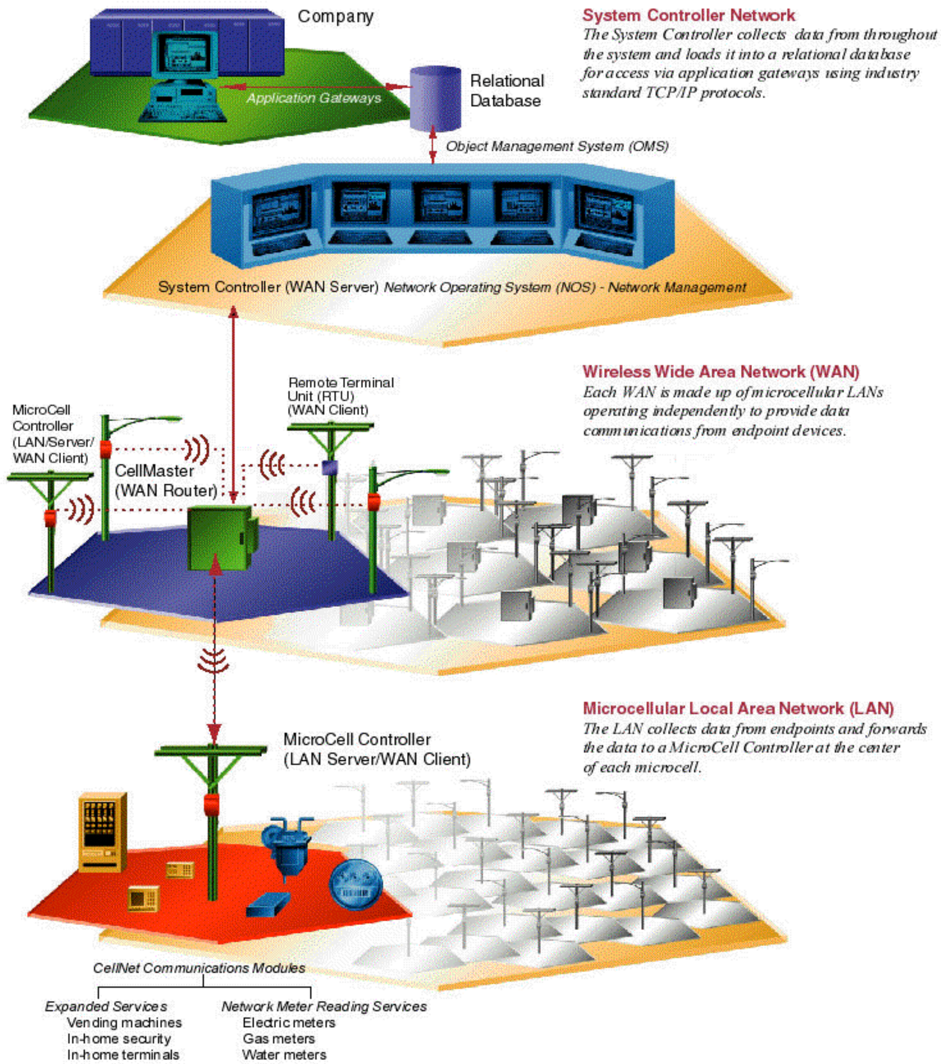

Figure 4.10 CellNet System Diagram

CellNet's wireless LAN (to the meter, etc.) communications use a direct-sequence spread spectrum radio technology ideal for economically and reliably communicating short bursts of data to and from millions of end points. Low-power links ensure minimal transmission interference, and built-in Cyclical Redundant Checking (CRC) error-checking protocols and hardware redundancy provide the highest data reliability.

5. Summary Prioritization and Comparison of Technologies

Table 5.1 compares the technologies / systems described in this report and their applicability to ancillary services. These technologies are identified as the ones that could permit near-term, widespread penetration of load management services as a system reliability resource in the ancillary services markets described in Section 3.

Table 5.1 Summary Comparison: Applicability of Technologies to Ancillary Services Markets

Technology	Regulation	Load Following	Voltage Control	Spinning Reserve	Supplement Reserves	Back-up Supply	Dynamic Scheduling	System Black Start	TOU	Real-Time Pricing
1-Way Direct Load	Marginal	Good	Good	Only If Modified	Good	Good	N/A	N/A	Good (Note2)	Good (Note2)
Schlumberger/CellNet	N/A	N/A	Good	Only If Modified	N/A	N/A	Good	N/A	Good	Good
Itron/Genesis	N/A	N/A	N/A	N/A	N/A	N/A	Good	N/A	Good	Good
ABB/Transtext	N/A	Good	N/A	N/A	Good	Good	Good	N/A	Good	Good
elutions (Interlane)	N/A	Good	N/A	N/A	Good	Good	Good	N/A	Good	Good
Main Street Networks	N/A	Good	N/A	N/A	Good	Good	Good	N/A	Good	Good
Teldata Solutions	N/A	N/A	N/A	N/A	N/A	N/A	Good	N/A	Good	Good
Meter Technology	N/A	N/A	N/A	N/A	N/A	N/A	Good	N/A	Good	Good
DCSI/TWACS	N/A	Good	Good	Only If Modified	Good	Good	Good	N/A	Good (Note2)	Good (Note2)
Cannon/Emetcom	N/A	Good	Good	Only If Modified	Good	Good	Good	N/A	Good (Note2)	Good (Note2)
Comverge	Good	Good	N/A	Only If Modified	Good	Good	Good	N/A	Good (Note2)	Good (Note2)
muNet	Good	Good	N/A	Only If Modified	Good	Good	Good	N/A	Good (Note2)	Good (Note2)
Internet Telemetry Corp	N/A	Good	Good	Only If Modified	Good	Good	Good	N/A	Good	Good
Nexus Data	N/A	N/A	N/A	N/A	N/A	N/A	Good	N/A	Good	Good

APPENDIX A

This appendix details the specifications of the key elements of a modified load management infrastructure that would be required for SCE's current direct load control infrastructure to provide the system reliability resources described in this report:

- load control receiver (LCR)
- data communications
- master computer
- metering system

A.1 Load Control Receivers

This subsection describes the technical and functional criteria for the Load Control Receivers (LCRs) that would be part of SCE's radio-based Direct Load Control system. These receivers are normally associated with the implementation of a mass market/ residential load management but can easily be adapted to commercial and industrial applications.

The system utilizes radio frequencies for communication, so system components must meet Federal Communications Commission (FCC) interference requirements. Any modifications to this system must be compatible with communications systems already in place, including commercial TV and radio as well as standard commercial, industrial, and public safety mobile radio systems.

A.1.1 Detailed Technical Specifications for LCRs

The subsections below list detailed technical specifications for LCRs.

A.1.1.1 General Requirements

General requirements for LCRs are:

- Operating Temperature -30 to +60° C
- Input Voltage capability and stability 24 VAC: +25% to -10% 120 / 208 / 240 VAC: +10% to -10%
  NOTE: one LCR would be used for low-voltage applications and another for high-voltage applications

A.1.1.2 Energy Consumption

LCR energy consumption should meet the following criteria:

- 24 VAC: 2.0 VA max. All internal and external relays de-energized.
- 12.0 VA max. All internal and external relays energized
- 120/208/240 VAC: Typical energy consumption for the non-energized state is 2.0 VA; when two internal and four external relays are energized, typical consumption is 8.0 VA.

A.1.1.3 Transient Voltage Protection

- LCRs should meet the latest American National Standards Institute (ANSI) specifications (current version is C37-91.1-1980). All products should have field test procedures that can be used to verify the functioning of the internal transient protection system. This testing permits operators to distinguish between microprocessor malfunctions and major problems that might require the product to be sent out for repair.

A.1.1.4 Physical Environment

LCRs should be able to withstand the effects of any anticipated external influences and weather conditions, including common-mode noise and low-level as well as high-frequency, fast-rise-time, low-energy transients. Most LCRs include "watchdog" timers that may be utilized to accomplish this task.

A.1.1.5 Factory Quality Assurance Testing

Utilities should verify that manufacturers test and "burn in" all units as they are built; this eliminates the need for on-site testing prior to installation.

A.1.1.6 Momentary Relay Contact Bounce

It is critical to end uses controlled by the system that LCR control relays do not momentarily change state (open and close) during a subtle LCR status change; this is especially important during power outages / restorations.

A.1.1.7 Thermostat "Droop" Compensation

LCRS should be designed so that an "open" / under control status of one of the low-voltage relays (to be designated R1) will cause a current of 8 milliamps (±1mA) @ 24VAC to flow through the "open" contacts into a resistive 3,000-ohm load. The circuit design voltage should be rated for 120 VAC. An onboard jumper, pin, or etc. should be provided that can be removed or cut to disable this current flow.

A.1.1.8 Radio Receiver Section

Operating frequency of the radio receiver station should be appropriate for the paging / dedicated system transmitter frequency, with the following additional characteristics:

- Spurious and Image Rejection - 40 decibels (dB) from carrier reference, measured when the receiver is matched to a 50-ohm impedance
- Capture Ratio - 6 dB maximum
- Selectivity - 50 dB @ ±20 kHz
- Frequency Stability - ± 0.002%, -30° C to +60° C
- Radio Frequency (RF) Sensitivity- With the receiver mounted in its normal vertical orientation, the maximum electrical field strength required for 100-percent operational success is 10 µV/m @ 2.0KHz frequency deviation when operating in the AFSK mode.

A.1.1.9 Control Relays and Remote Relay Driver

General Specifications for control relays and remote relay driver are a life expectancy of 100,000 operations at rated load and a voltage rating of 2 kV @ 60Hz.

The internal relays should meet the following specifications:
- Low Power: Two Form-C Contacts (R1 & R3) should be provided with a rating of five amps @ 120 VAC (resistive load) <u>and</u> 40 VA @ 24 VAC (inductive)

- High Power: One Form-B relay (R2) should be provided with a minimum rating of 30 amps @ 240 VAC (resistive load) <u>and</u> 1 HP @ 120 VAC (inductive).

The external relays should meet the following specifications:
- Low Power: Three Form-C Contacts, 5 amps @ 120VAC (resistive load) and 40 VA@ 24VAC (inductive), 24-Volt AC coil voltage, with integral wiring harness compatible with manufacturer's standard wiring color code. All conductors should be # 18 AWG and at least eight inches in length. This relay interfaces with the internal R1 relay to meet the occasional need for more than one control contact operating in conjunction with R1.

- High Power: One Form-C relay, 30 amps @ 240VAC (resistive load) and 1 HP @ 120 VAC (inductive), in a weatherproof enclosure with integral wiring harness compatible with the remote driver circuit specified in the next section. The high-voltage leads should be at least # 12 AWG, the low-voltage # 18 AWG; all leads should be at least eight inches in length.

- Remote Relay Driver Circuit (R2A) - The LCR should be capable of remotely controlling an externally mounted relay from its internal power supply. When energized for control activity, this circuit should be rated for continuous duty operation and should always operate in complete synchronization with the internal high-power relay (R2).

A.1.1.10 Functional Specifications

- Digital Message Protocol / Decoder Requirements

LCRs should utilize a robust communications protocol that is readily available from the manufacturer's standard product offerings. Typically approved load management message protocols are:
- Cannon Technologies, Inc. - STANDARD VERSACOM and EXTENDED VERSACOM
- Regency Technologies - STANDARD VERSACOM and VCOM (if available)
- Comverge Technologies, Inc. - SA 205 / 206 / 305

One desirable protocol feature relates to synchronization of low- and high-power relays. The low-power relays (R1 & R3) should always start control at the same time (assuming that a "shed" command for both relays has been received by the load control device). The high-power 30-amp relay (R2) and remote control driver circuit (R2A) must always be completely synchronized. Both sets of relays (low and high power) may be synchronized by random chance; they should not be forced into synchronization. The two low-power internal relays each have selectable time-out characteristics or duration parameters but must begin control in synchronization. The remote relay driver circuit for the remote control of an external relay should always be in synchronization with the high-power relay (start and stop). This synchronization requirement is necessary because the low-power relays may be controlling a portion of the same appliance; their coordination ensures the implementation of fail-safe appliance control logic. The high-power relay and remote driver will not necessarily control portions of the same appliance, but the appliances they control will likely be similar or related, i.e., pool pump and pool sweep.

- Tamper Detect and Notification

The LCR should be able to detect unauthorized disconnection by sensing occasional current flow through the internal relay contacts. An internally set time frame determines how long a "no-current" (presumed disconnect) condition can exist before a "tamper" is registered. The receiver should have a visual indication of this "tamper detect" status. It should not be reset by power outages, and a typical time frame would be 90 days. The actual time frame will be downloaded to the receiver through the communications protocol.

- LCR Failure Rates

Manufacturers should specify a maximum guaranteed annual failure rate for LCRs.

- Cold Load Pickup

Cold load pickup is the unilateral action taken by an LCR when power is restored after an interruption. This action normally involves the implementation of a control or shed action for some if not all control functions. The effect of this operation is to keep certain customer appliances off for a period of time immediately after power restoration in order to reduce the magnitude of the now-synchronized electrical load on the distribution circuit (i.e., all natural diversity of electrical loads is lost after a power outage). The reduced demand on the electrical circuit will significantly assist the utility's attempts to restore power.

Receiver persistence is the LCR's ability to ignore short-term (typically one- to three-minute) power outages. This feature in the cold load pickup application allows the receiver to continue to carry out the instructions that it last received and to address the unique relationship between cold load pickup and any existing control action as dictated by the system's implementation strategy.

The cold load pickup status of the receiver (enabled or disabled) should be user programmable and selectable for each individual control relay. The receivers should be shipped from the factory with cold load pickup enabled so that the installers will not have to address nuisance control.

- Historical Event Counters

LCRs should store various operational parameters, including the number of times each relay and driver circuit operate; the number of radio signal receipt verification / internal diagnostic test commands passed; the elapsed time since receipt of memory clear; all receiver *individual*, *group*, *division, substation*, *feeder*, *transformer*, etc. address information; tamper detect information; and cold load pickup status. This information should be read and reset locally without opening the receiver compartment by means of a handheld portable test device. It should be possible to freeze all internal memory counts from the Master Station Controller so that this information can be retrieved at a later date. Freeze commands should be implemented using the master station software and system communications protocol.

- Internal Diagnostics

LCRs should automatically monitor their own functional status. Results should be indicated on the LCR the visual display so that an inspector can readily see them. Monitoring should include verification of internal relay continuity (coil), microprocessor internal function, and transmitted message error detection (i.e., CRC implementation.

- Receiver Visual Indicators

LCRs should be designed to include visual status indicators that are viewable without opening the receiver enclosure. These visual indicators are typically LEDs that display the status of controlled loads as well as the condition of the receiver itself. This function also includes optical transmission of data to an external test device.

- Test Equipment

Test equipment that can implement all aspects of the LCR capability should be a part of the manufacturer's package. This equipment should be used for installation, troubleshooting, and verifying system performance.

- Universal Telecommunications Capability

LCRs should be designed and built to become compatible with the two-way interactive telecommunications technologies currently becoming available, including Hybrid Fiber / Coax, Satellite, Ethernet Local Area Networks (CEBUS, LONWORKS), etc. This capability should be in the form of a universal interface arrangement so that a plug-in daughter board can be installed to provide an interface with the network being deployed. The LCR itself is generic, but the daughter board is specifically designed for a particular telecommunications interface. This option should allow access to the receiver's various status parameters stored in memory. The retrievable information should, at a minimum, equal the data available through the remote optical reader device.

- Physical Configuration

The enclosure should be a rain-tight enclosure with a hinged door, National Electrical Manufacturers Association (NEMA) 3R, suitable for outdoor installation. Mounting tabs should support the physical attachment of the receiver to the customer structure. The enclosure should also be approved and listed by the appropriate national standards, particularly Underwriters Laboratory (UL) 916. Wiring entrances should be clearly described. At least one 3/4" nipple with a bug seal around all exiting wire pigtails should be provided. An alternate approach could include an internal junction box for high- and low-voltage power relay connections.

- External Wire Specifications
  -Insulation (All conductors) - 600 VAC, 105 °C
  -Conductor Size
    Low-Power Relays and Remote Driver Circuit - #18 AWG Strand
    High-Power Relay - #12 AWG Stranded
    Power Supply Input - #18 AWG Stranded
    Length - All conductors eight inches in length
    Color Code - Manufacturer's Standard Offering

- Internal and External Labels
  All external labels should conform to UL listing requirements and be designed not to fade or become brittle from outdoor conditions for a period of 20 years.

- Labeling information
  A front cover label should show the receiver PC board serial number and the utility corporate logo. A receiver wiring interface diagram should appear on the inside of the enclosure back panel. A removable inventory control label should be available to be attached to an installation work order for tracking purposes.

A.1.2 Industry Standards

All LCRs should conform to the latest version of the following standards or the requirements of the following agencies:

National Electric Code
American National Standards Institute
Institute of Electrical and Electronic Engineers (IEEE)
American Society of Mechanical Engineers
National Electrical Manufacturers Association (NEMA)
Underwriters Laboratory (UL)
Federal Communications Commission (Part 15)

A.2 Data Communications

The load management master station controller typically connects to three separate data networks. The first and simplest controls remote transmitters, usually through a standard, four-wire, 600-ohm balanced, phone-line type circuit. The load management vendor typically supplies all hardware and software necessary to remotely interface with the selected paging / private radio transmitter system.

A remote transmitter controller (RTC) is typically used for a dedicated / utility-owned transmitter system. The physical interface between the RTC and the RF transmitter system is unique and is normally be described in detail in a vendor's response to a Request for Proposal.

Using today's technology, it is assumed that the RF modulation of the transmitter will be Frequency Shift Keying (FSK), commonly referred to as digital transmission. With this type of transmitter modulation, the remote transmitter controller must generate the appropriate mark / space digital outputs.

The transmitter control for a paging system normally uses the paging system's standard interface for sending pages. The load management system's control message / protocol is converted to an ASCII format and is transmitted as a page to the LCR. A paging-based system worth serious consideration offers the flexibility to switch paging carriers after LCRs are installed in the field; business conditions or technical problems could prompt a need to switch paging carriers.

Typical Load Management System Interface / Data Flow

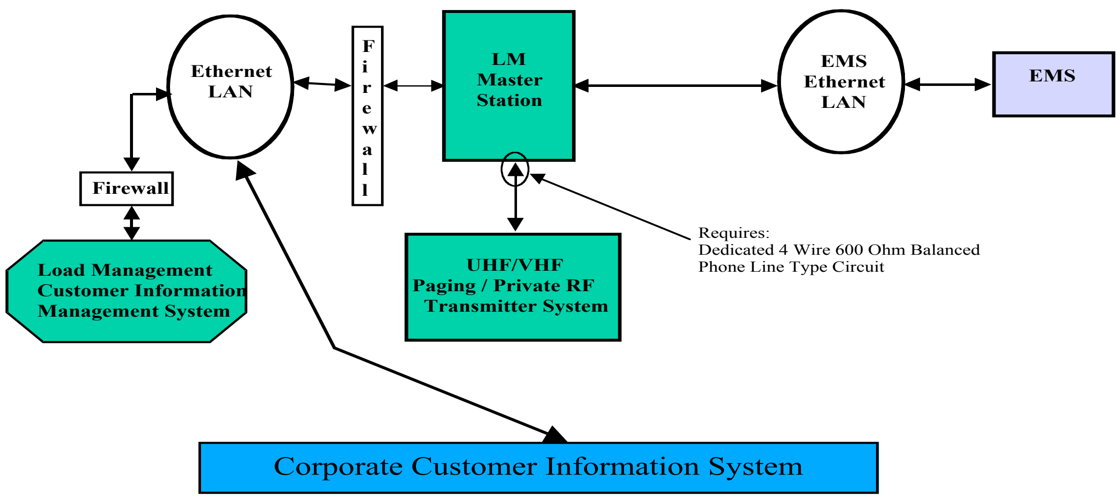

Figure A .1

The second load management master station controller data interface requirement involves the Energy Management System (EMS) / Supervisory Control and Data Acquisition (SCADA) system. A typical EMS could be running on a redundant IBM 360 with a universal interactive executive (UNIX) operating system. EMSs often utilize an Ethernet Local Area Network (LAN) for local networking. The load management master station controller connects to the LAN via an RS232 serial interface that could be provided by a component of the EMS package. An alternative interface is a direct connection to the Ethernet LAN through an existing unused tap. All data transfer between the EMS and load management master station controller will normally pass through this physical interface.
The external interface to the EMS may require a special software package. The utility should assist in determining the nature of that software and any other coordination required between an EMS vendor and a load management system contractor. Any modification or enhancement of

the EMS for the implementation of a load management system should be included in the scope of a direct load control system specification and should be part of the system provider's cost estimate. Likely modifications to existing EMSs should include a program that will implement the dispatcher interface and allow for passage of system status and control information to and from the EMS. It is recommended that the load management system supplier contract directly with the EMS vendor to implement the vendor's specific interface requirements.

The load management master station controller interface is for all data transfers between the load management master station controller and the load management Customer Information Management System (CIMS), utility Customer Information System (CIS), trouble management, marketing, and project management personnel. This interface will normally be made directly to an existing company Ethernet LAN.

A.2.1 System Security Architecture Issues

System security is discussed in the subsections below.

A.2.1.1 Securing Physical Interfaces

As indicated in Figure A.1, all physical interfaces among the proposed load management CIMS, the load management master station, the existing corporate internal network, and the EMS network should be protected with appropriate security devices (routers or firewalls) so that only authorized individuals or processes can access these systems. Product vendors should work with the utility's network architecture and information technology (IT) security personnel to ensure the appropriate configuration and integration of these devices with the proposed system.

A.2.1.2 User Authentication to System

User access to the proposed load management system should be restricted using an approved, industry-standard authentication mechanism. An example of an approved mechanism would be signed certificates and a SSL protocol from an internet browser on each end user's workstation.

A.2.1.3 Dial-up Access

Remote dial-up access to the system should be supported by the vendor utilizing a secure dial-up mechanism (Shiva's LanRover Access Switches w/ AceServer SecureID validation would be an example). Direct modem connections to any of the load management system components (server, workstations, etc.) would not normally be allowed.

A.2.1.4 Applications Systems Interfaces

All interfaces to existing applications from the load management system should be approved by the corporate IT application support group responsible for maintaining those applications.
Any batch data transmissions that may a part of the load management system interface should use secure, encrypted, industry-standard protocols. An example of this would be the secure shell

(SSH) protocol. Non-secured, non-encrypted file transfer protocol transmissions between internal systems and external vendor-supported systems would not normally be allowed.

A.2.1.5 Very High-Frequency (VHF) / Ultra High-Frequency (UHF) Radio System Design

The utility typically determines the expected coverage for signal reception for the load management radio system. The system vendor and paging system vendor provide radio system coverage data if the system is implemented using an existing paging infrastructure. Communication is typically considered successful with a 95-percent success rate, 95 percent of the time.

A.3 Master Computer

The general specifications for a Master Computer system for a typical radio-based, one-way direct load control system are summarized in the subsections below.

2.3.1 General Hardware Requirements
The system vendor will normally provide all equipment necessary for implementation of a complete Master Station Controller System, including computers, keyboards, monitors, printers, interface ports, modems, and ancillary interface equipment.

The master station controller system platform should be state-of-the-art IBM-compatible personal computers adequate to support the functional requirements described in this report. It should be possible to upgrade the system to a fully redundant configuration based on the manufacturer's standard failure-sensing scheme.

Typical system components are:

- Pentium III IBM PC-compatible computer with keyboard and mouse
- 19-inch high-resolution super video graphics array (SVGA) or better color monitor
- 128 megabytes (MB)of random access memory (RAM)
- 40-gigbyte (GB) hard drive, minimum
- compact disc (CD) read/write drive (8x or better)
- 3.5 floppy disk drive
- printers - report and event
- modem for transmitter control
- 56-Kbps dial-up modem for remote access
- 10/100 Ethernet Network Interface Card

The master station controller should include a real-time clock configured so that time and date will not require reinitialization after power outages. An interface with an existing SCADA / EMS system clock is a desirable strategy for meeting this requirement.

Remote dial-up access to the master station controller may be provided via a 56-Kbps modem. The option to add a second dial-up modem is desirable. System access must conform to all corporate security requirements.

A.3.2 General Software Requirements

The Master Station Controller System should utilize an advanced multi-tasking operating system capable of supporting multiple simultaneous programs, a graphical user interface, and queued, prioritized commands. The complete operating software package should be furnished, including the source code. The manufacturer could, as an option, establish a trust that could be used to guarantee access to the code. The intent is to prevent problems with software maintenance and/or enhancements if the vendor goes out of business or terminates its support of the system.

The graphical user interface for the master station controller system should use a Windows format that supports a multi-tasking environment. This interface should provide operational and diagnostic aids, including on-line “help” functions.

If there is a loss of power to the master station controller, the computer must automatically restart and resume control without operator intervention.

The master station controller’s database should be fully relational with structured query language (SQL) compatibility. The database files should utilize a standard database package such as MS Access, Microsoft SQL Server, Oracle, etc. Proprietary, vendor-specific database file formats are normally not acceptable.

The master station controller should provide a real-time and historical facility that allows the graphing of any data points that have been stored in the system. This capability must be extremely user friendly, including a context-sensitive help system, graphical interface, and cursor-driven editing. Standard 24-hour system load curves should be available, including the ability to display the time and value of any point in the display.

A.3.3 Functional Requirements

Load management control “strategies” (consisting of multiple control commands) will normally be initiated by one of the following means: a time-of-day schedule, external data input (such as the automated ancillary service requirements specified in this document), or in response to a specific command from the system operator. External operation includes “feedback” mechanisms that automatically initiate load control to manage total system demand or, additionally, transmission, distribution feeder, and substation demand to a desirable limit. This application requires system load / demand inputs [provided by the EMS / Independent System Operator (ISO)] from various metering points strategically placed throughout the service territory. From these data, the system projects the need for load management and responds accordingly. A typical dispatcher-initiated control strategy could be derived from a MW load reduction value that has been input to the system. The load management master station software will initiate the control strategy that corresponds to that level of reduction. The dispatcher may also request an increase or decrease in load reduction during the run time of the previous operation, and the system must automatically adjust to that request.

Control strategy prioritization should allow the system administrator to assign the priority order in which several simultaneous control strategies will be implemented. The system dispatcher should be able to link these "prioritized" strategies to system events.

The system should be able to integrate all automatic control activities while providing the dispatcher with override capability. The system dispatcher must be able to modify automatic control in any way that meets system requirements, i.e., increase or decrease load reduction, cancel control, etc.

The direct control (load off) of specific customer appliances for various extended periods of time should be supported. This should include the ability to execute a delay period before operation and to initiate a control activity that will continue for a period of time specified by the operator. The restoration activity should be based either on a time-out characteristic or the implementation of a "distributed intelligence" control. Distributed intelligence is a form of random control intended to ensure a smooth process. It can simulate natural appliance diversity even after an extended load-shedding event. This type of load management is described in detail in Section 2.1.1. The distributed intelligence specification is included in the receiver specifications because this capability is, by definition, provided by the software within the load control device rather than the master station.

Cyclic control should allow the system operator to implement various duty cycles and cycle periods for different types of loads, i.e., the time base for load control should be selectable. An example would be a time base that would allow loads to be shed regularly for some specified amount of time, e.g., 10 minutes out of every 30 minutes. Ten minutes off during a 30-minute time base is a 33-percent off-time duty cycle. The user should always define these parameters.

The system dispatcher should be able to terminate load control immediately or by using the distributed intelligence capability described above.

The load management master station controller should support a protocol that delivers an individually addressable (Direct Load Control Switch) load management control system. The number of available addresses is typically in the millions. The master station should also be able to implement various hierarchical characteristics inherent in the protocol. A typical hierarchical structure is: System Address or Utility I.D.; Utility Division; Substation; Feeder; Transformer, etc. The manufacturer should reserve a sequential series of serial number addresses for all future purchases for this system. This range of numbers will typically provide millions of individual addresses / serial numbers.

The load control receiver address / configuration assignment is coordinated by the load management master station controller and the Customer Information Management System. Customers should be able to vary their load management participation, which will mean changing their control specifications. Changes are implemented using the system protocol and link back to the individual customer address that the protocol provides. Bidders proposing to provide load management control services should describe in detail their methods of determining the customer's participation variables.

Cold load pick-up, the ability to automatically shed customer appliances when power is restored after a sustained outage, should be supported so that each receiver control relay can have its own downloadable cold load pick-up configuration via the load management master station controller. Bidders to provide load management services should describe their standard methodologies for implementing Cold Load Pickup.

The load management system should account for whether a customer is “in” or “out” of service. When a customer is out of service, the receiver should respond only to a command to return the customer to active service; it should not respond to control or cold load pickup commands. The system should support identification of customer status based both on contractual agreements and temporary changes in status in response to customer requests. Temporary status changes should be failsafe so that the customer is automatically restored to normal status after a predetermined time period. Customer service status should also be stored in nonvolatile memory.

The load management system should be able to command the LCR to implement an internal diagnostic test and radio signal receipt verification. The system should be capable of implementing this test sequence approximately once per minute during idle system conditions. The test signal will be utilized by installers and troubleshooters to quickly the status identify of the LCR.

To support troubleshooting analysis, a history of control activity and other relevant information for each receiver should be maintained in the Master Station Controller database as well as the LCR itself. The load control and communications success information stored in the receiver memory should be locally accessible by means of portable test equipment; this equipment and the Master Station Controller should both be able to reset this information to zero. The ability to freeze receiver memory counters is also desirable.

A.3.4 Customer Information Management System (CIMS)

A CIMS is a critical separate component of the system because the required functionality cannot or may not be provided using the existing corporate Customer Information System (CIS).

The CIMS should be used for tracking and generating load management customer participation information. The system should accommodate real-time inquiries about the control status and control history of individual customers, summary reports, work order forms, and other customer service activities.

The load management CIMS should reside on its own dedicated platform and located with the Load Management Master Station Controller. It should interface with the load management master station controller using the existing corporate local area network.
Some of the specific items that should be tracked are:

- customer name
- account number
- Address
- phone number(s)

- switch (LCR) serial number
- switch (LCR) address settings and configurations
- date of sign up
- date work order assigned to contractor
- installation date
- cold load pick up status
- in- and out-of-service history
- load management hardware inventory
- customer appliance statistics, i.e., (BTU, watts, gallons, condition, etc.)
- utility electricity service information:
- Division, substation, feeder, transformer, pole, etc.
- Customer control history

Multiple switch installations per customer location should be supported. The database should accommodate millions of customer records.

The system should also provide numerous reports relating to customer status, installation specifics, trouble call history, cycling history, etc. An example would be a report writer such as Seagate Crystal Reports, which is a widely used windows tool.

The existing corporate CIMS should transmit a standard-format (e.g., ASCII) file to the load management CIMS each night. The load management CIMS should use this downloaded file to add and delete customers to/from the load management program and address any other customer participation criteria. The file transfer should include customer information from the corporate CIS (Name, Address, Phone number, Account number, etc.). On a nightly basis, the load management CIMS will create a standard format file of control activities that have taken place since the previous upload. This file will be uploaded from the load management CIMS and used to create the daily transactions history necessary for the mainframe corporate CIS. Periodically, e.g., on a monthly basis, the entire load management CIMS "customer information" will be updated from the corporate CIS. This should ensure that the two systems' customer records remain consistent.

Typical system components are a 500-MHz Pentium III IBM PC-compatible computer with:

- keyboard and mouse

19-inch high-resolution (SVGA or better) color monitor

- 128 Mbytes of RAM
- 40-Gbyte hard drive, minimum
- CD R/W drive (8x or better)
- 3.5 floppy disk drive
- printer
- 56-Kbps dial - up modem for remote access
- 10/100 Ethernet Network Interface Card

- ORACLE database structure

Figure A.2. shows a flow chart representation of a load management CIMS.

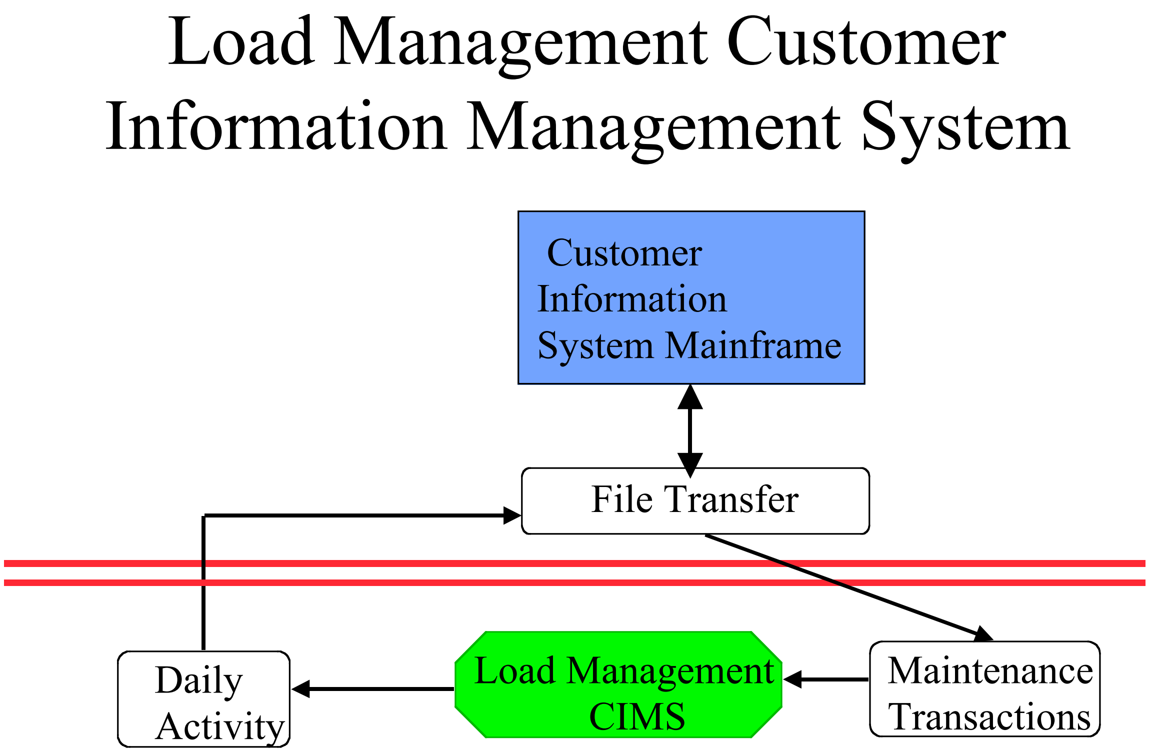

Figure A.2

APPENDIX B

A relatively new product currently being manufactured by SmartSynch Corporation and marketed through Siemens would be an ideal addition to a direct load control system that is used to implement voltage control by managing reactive power elements on the distribution system. The SmartSynch system provides not only three-phase power information (interval data, etc.) but

basic power quality information including voltage sags, swells, etc. The actual number of SmartSynch meters would be limited to the number of reactive power elements under control; therefore, the overall cost impacts of adding this product to a system would be negligible. SmartSynch provides a SkyTel communications package that fits under the glass of poly-phase electricity meters (currently Siemens S4, others under development). The communication package delivers consumption and demand data and can also deliver the entire meter database. The SmartSynch system determines customer-specific power quality parameters and reports any desired alarm condition. The power quality portion of the system is event driven. The communication module, power supply, and antenna are all self-contained under the meter cover, resulting in significantly lower installation costs.

SmartSynch delivers wireless, two-way IP connectivity to energy and utility companies and provides a cost-efficient AMR capability for C&I customers. Smart meters generate and transmit data on the quantity of the resource used and the quality of its delivery. Power-quality and reliability reporting functions allow the utility company to inform C&I customers immediately of outages, interruptions, or fluctuations. These value-added, fee-paid services offer customers critical information while providing the utility company an opportunity for additional revenue streams. The return on investment (ROI) cycle for the utility company can be less than two years compared to the ROI for phone modem systems. The customer / utility notification system uses the SkyTel two-way paging network and email.

The benefits to the utility of this system include:

- Automated network registration and coordination offer “plug and play” meter commissioning. No coordination of modem, meter, communication circuits, and master station means low-risk, rapid deployment and reduced project costs.

- M32 Transaction Server (Windows NT)
  The “head-end” transaction management system, M32, was developed to leverage multiple processors and distributed NT computing, and complement other Microsoft applications. It is object oriented; the M32 system is configured using drag and drop objects, wizards, etc. It has built-in SQL and ODBC permitting sharing of information throughout an enterprise, i.e. MV-90 and / or Energy Interactive for instance for web posting, etc. The M32 head end may be purchased for on-site deployment or an application service provider contract can be negotiated with SmartSynch to provide the M32 on an outsourced basis.

- Spectrum Information Efficiency for the SkyTel System

Low data overhead because of innovative data parsing, data compression, and protocol management at both the meter and the host

- IP Data with Forward Error Correction (FEC)
  Interlocked packet switched IP data with FEC for data security and efficiency.

- Power-Quality / Reliability Reporting Functions
  Outage reporting, sag/swell alarms, volts/amps per phase, voltage imbalance, nominal voltage, etc. Offers C&I customers a value added (fee paid) service. The ability to calculate and report phase-to-phase voltage problems directly from the meter is unique in the industry as is the ability to select customer-specific parameters for alarm reporting.

- Wireless Benefits
  In contrast to phone modem technology, SmartSynch meters are wireless IP devices that are always on and always connected to the network and the internet. This continuous connection with the SkyTel network via the Narrowband PCS Control Channel provides the time-synchronization process so critical for accurate demand and interval data reporting as well as maintaining the accuracy of the internal meter clock.

- Two-Way Internet Connectivity
  With event-driven alerts, the SmartSynch system uses paging (wireless messaging to individuals or groups), automated e-mail, fax, and phone messages with web interface to give the utility and its customers access to data reports.

- Motorola CreataLink 2XT Transceiver
  A mass-produced and field proven WAN gateway device with critical mass economies of scale and high reliability provides the basic RF communications capability. Two-Watt RF output and +3 dB gain internal antenna result in outstanding RF field performance and superior "in building" penetration.

- No Additional Field Network Infrastructure Required
  No towers, repeaters, routers, transmitters, receivers, batteries/UPS, no site leases, no telephone company contracts, etc.

- Premium Integrated Data Network - SkyTel
  By using an established (hardened) commercial RF communications infrastructure, the utility can eliminate licensing, design, construction, operation, maintenance, and risk of a less robust private network and can share high infrastructure costs with other commercial users.

- SkyTel simulcast communication
  Supports multiple transmitter and receiver network coordination in same end-point area for superior in-building penetration.

- SkyTel broadcast capabilities
  For load curtailment, RTP, device reprogram, messaging, etc. not supported by PSTN and some wireless networks.

- Full two-way customer communication
  Supports outage and restoration notice, spontaneous power-quality events, load control, RTP, remote connect/disconnect, pre-pay metering, two-way customer messaging, and other value-added services.

- IP addressable SkyTel wireless network is an extension of the internet that powers all SmartSynch meters field devices as nodes on the internet.

- Nationwide data network with costs that do not change with message distance, i.e., no long-distance toll charges for distant or national C&I accounts.

- Extensive RF coverage network and a cooperative network service provider strategy to customize coverage and meet future AMR service requirements.

Simple meter installation procedures and tools such as the portable, lunch-box-sized RF Coverage Validation Unit (CVU). The CVU is a self-contained go/no-go device that automatically records site metrics and is designed to be used by workers with minimum skills.

- Handheld Motorola PageWriter 2000 wireless PDA facilitates meter installation and serves as a remote wireless operator interface with the SmartSynch / SkyTel system.

- Efficient Messages - size and structure are optimized for AMR data payloads.

- On September 25, 2000 SmartSynch announced that, in partnership with Siemens Power Transmission & Distribution, Inc., it has added power quality and reliability monitoring to its energy and utility wireless data services portfolio. As mentioned earlier, Siemens markets the system to utilities throughout the U.S.